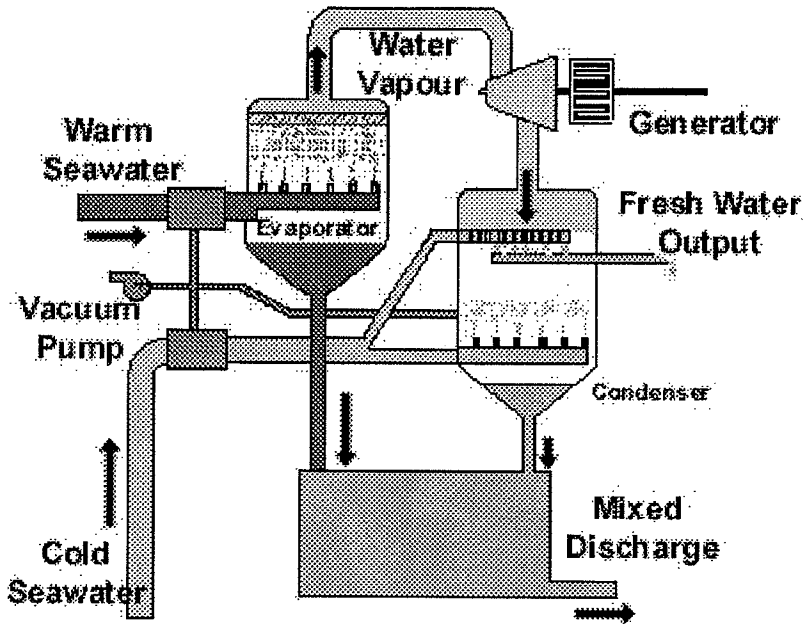
Figure 14: Open-Cycle OTEC System



Source: EREN

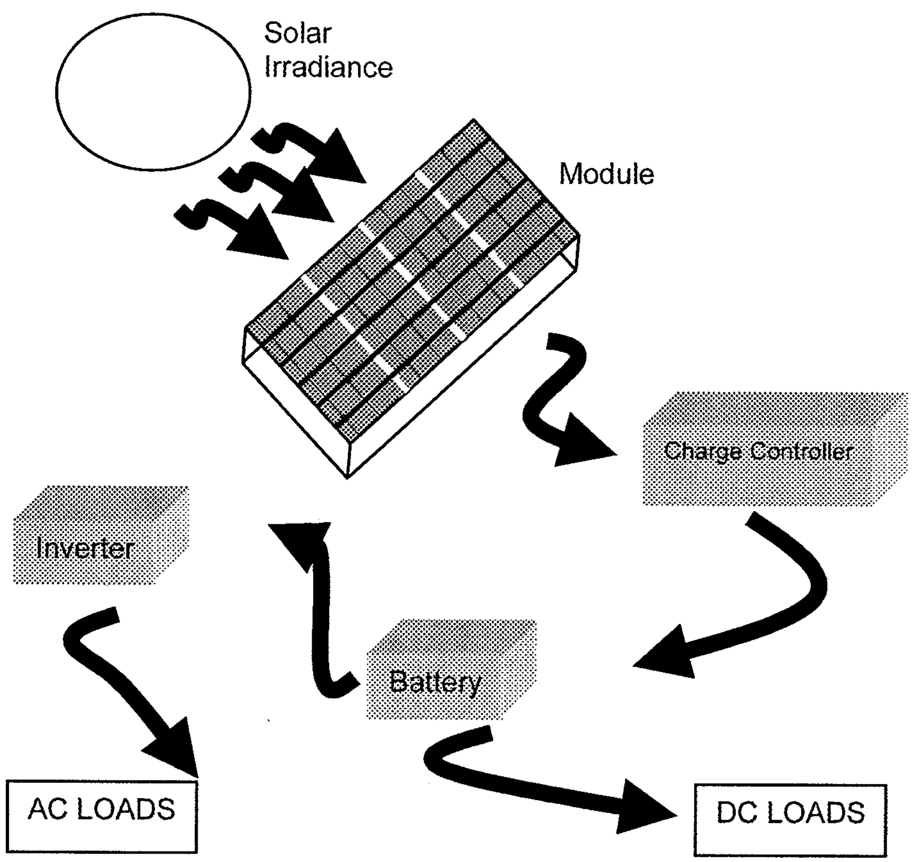
Solar

Photovoltaics

Photovoltaic (PV) systems directly convert light energy into electricity in large-area, solid-state semiconductor devices made up of many individual PV cells. Photovoltaic cells convert light energy into electricity at the atomic level. When photons of sunlight strike a PV cell, they may be reflected or absorbed, or they may pass right through. Only the absorbed photons with a certain level of energy are able to free electrons from their atomic bonds to produce an electric current.

All solar cells have at least two layers: one that is positively charged and one that is negatively charged. The electric field across the junction between these two layers causes electricity to flow when the semiconductor absorbs photons of light and releases electrons. The greater the intensity of the light, the more power generated by the cell. PV systems are designed and sized to produce the desired electrical output. The addition of electrical power conditioning components (electrical switches, diode protection circuits, DC-to-AC inverters, etc.) are required to interface the PV output with the electrical load.

Figure 15: PV System Schematic



The conversion efficiency of a PV cell is the proportion of sunlight energy that the cell converts to electrical energy. This is very important when discussing PV systems, because improving this efficiency is vital to making PV energy competitive with more traditional sources of energy. Naturally, if one efficient solar panel can provide as much energy as two less-efficient panels, then the cost of that energy will be reduced. For comparison, the earliest PV systems converted about 1-2% of sunlight energy into electric energy. Today's PV systems convert 7-17% of light energy into electric energy.

Certain materials naturally release electrons when they are exposed to light, and this can produce an electric current. One of the most common of these materials is silicon, which is the main material in 98% of solar cells made today. PV modules are designed and sized to produce the desired electrical output. The actual power output depends upon the intensity of sunlight, the operating temperature of the module, and other factors. There are four main technologies for PV cells.

- *Monocrystalline Silicon*: Made using thick cells saw–cut from a single cylindrical crystal of silicon, this is the most efficient of the PV technologies. These cells are highly efficient, but the manufacturing process to produce monocrystalline silicon is complicated, resulting is slightly higher costs than other technologies.
- *Multicrystalline Silicon*: Made from cells saw–cut from a cylindrical ingot of melted and recrystallized silicon, creating a granular texture. In the manufacturing process, molten silicon is cast into ingots of polycrystalline silicon, these ingots are then saw-cut into very thin wafers and assembled into complete cells. Multicrystalline cells are cheaper to produce than monocrystalline cells, however they also tend to be slightly less efficient.
- *Thick–film Silicon*: Another multicrystalline technology where the silicon is deposited in a continuous process onto a base material giving a fine grained, sparkling appearance. Like all crystalline PV, this is encapsulated in a transparent insulating polymer with a tempered glass cover and usually bound into a strong aluminum frame.
- *Thin–film Silicon*: Three very thin layers of silicon are deposited on a lightweight stainless steel substrate in a roll–to–roll process, using a gas in a vacuum. The steel backing and a weatherproof polymer coating make this product both flexible and extremely durable.

Table 2: Solar Technology Performance Guide

	Mono	Multicrystalline	Thick Film	Thin Film
Efficiency at Turning Light into Electricity	15%	12%	10%	6%
Area needed per Kilowatt (Square Meters)	8	11	12	16
Efficiency in Low Light Conditions	good	good	very good	excellent
Environmental Rating	good	very good	excellent	excellent

Source: Bergey WindPower

Electrochemical PV cells are another technology for PV that is currently in development. Unlike the crystalline and thin film solar cells that have solid-state light absorbing layers, electrochemical solar cells have their active component in a liquid phase. They use a dye sensitizer to absorb the light and create electron-hole pairs in a nanocrystalline titanium dioxide

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semiconductor layer. This is sandwiched between a tin oxide coated glass sheet (the front contact of the cell) and a rear carbon contact layer, with a glass or foil backing sheet. Some consider that these cells will offer lower manufacturing costs in the future because of their simplicity and use of cheap materials. The challenges of scaling up manufacturing and demonstrating reliable field operation of products lie ahead. However, prototypes of small devices powered by dye-sensitized nanocrystalline electrochemical PV cells are now appearing (120cm^2 cells with an efficiency of 7%).

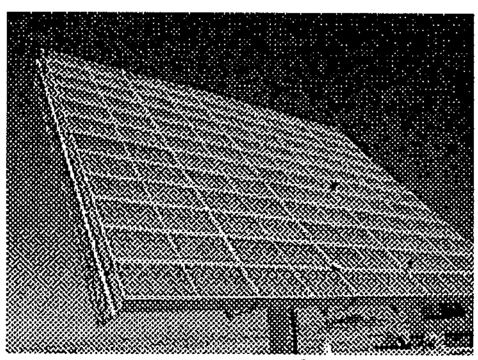
For residential and commercial applications, pre-engineered packaged modules are available which provide 120V AC electricity -- beyond the power lines. Systems are usually expandable to maximize power production without changing electronic controls. Usable AC power production generally is based on 6 peak average daily sun hours, including losses for battery charging and inverter efficiency. A typical off-grid module will provide 4kWh/day at 120VAC. Most typical 24VDC solar charging systems will power most household appliances and sensitive AC loads. Systems generally include a solar electric array, a 24V inverter about 4000 watts @ 120VAC pure-sine wave with automatic battery charger, and a programmable control center.

Conventional solar electric systems use solar cells, encapsulated in "flat-plate" weatherproof "modules." Solar cells cover the entire flat-plate module area and are uniformly illuminated with unconcentrated sunlight. In contrast, a high concentration photovoltaic (HCPV) system uses a plastic Fresnel lens, similar to those found in overhead projectors, to concentrate sunlight many times before it reaches the solar cells. Alternatively, reflective mirrors can be used to concentrate the sunlight.

High Concentration Photovoltaics

The basic concept of High Concentration Photovoltaic (HCPV) systems consists of replacing large areas of high-priced solar cells with inexpensive optics and a small number of solar cells. When sunlight concentrated 300-times illuminates a solar cell, that cell will produce about 300-times more power than it would without concentration. Concentrating lenses and solar cells are assembled together in a plastic housing to form a weatherproof concentrator module. Because of the concentration optics, concentrator modules must be pointed at the sun, so the sun is tracked on two axes, thereby allowing the system to produce more energy annually at a much lower cost.

Figure 16: HCPV System



Source: EREN

A typical basic concentrator unit consists of a lens to focus the light, a cell assembly, a housing element, a secondary concentrator to reflect off-center light rays onto the cell, a mechanism to dissipate excess heat produced by concentrated sunlight, and various contacts and adhesives.

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Besides increasing the power and reducing the size or number of cells used, concentrators have the additional advantage that cell efficiency increases under concentrated light. How much the efficiency increases depends largely on the cell design and the cell material used. Another advantage of the concentrator is that it can use small individual cells -- an advantage because it is harder to produce large-area, high-efficiency cells than it is to produce smaller-area cells.

There are, on the other hand, several drawbacks to using concentrators. The concentrating optics they require, for example, are significantly more expensive than the simple covers needed for flat-plate modules, and most concentrators must track the sun throughout the day and year to be effective. Thus, higher concentration ratios mean using not only expensive tracking mechanisms but also more precise controls than flat-plate systems with stationary structures.

High concentration ratios are a particular problem, because the operating temperature of photovoltaic cells increases when excess radiation is concentrated, and this creates heat. Cell efficiencies decrease as temperatures increase, and higher temperatures also threaten the long-term stability of PV cells. Therefore, HCPV cells must be kept cool.

There are three main reasons why HCPV systems have not yet been widely adopted. First, the added complexity of tracking required for PV concentrators is not cost-effective for PV systems smaller than 1 kilowatt in size (currently the bulk of the PV market). Second, there is a widely held belief that concentrator systems can be effective only in areas with exceptional direct solar radiation resources, such as the desert Southwest U.S. Finally, the performance and reliability experience of the few commercial HCPV systems installed to date has been very disappointing.

Concentrating Solar Power

Concentrating solar power plants produce electric power by converting the sun's energy into high-temperature heat using various mirror configurations. The heat is then channeled through a conventional generator. The plants consist of two parts: one that collects solar energy and converts it to heat, and another that converts heat energy to electricity. The amount of power generated by a concentrating solar power plant depends on the amount of direct sunlight. These technologies use only direct-beam sunlight, rather than diffuse solar radiation. There are three kinds of concentrating solar power systems -- trough systems, power tower systems and dish/engine systems -- that are classified by how they collect solar energy.

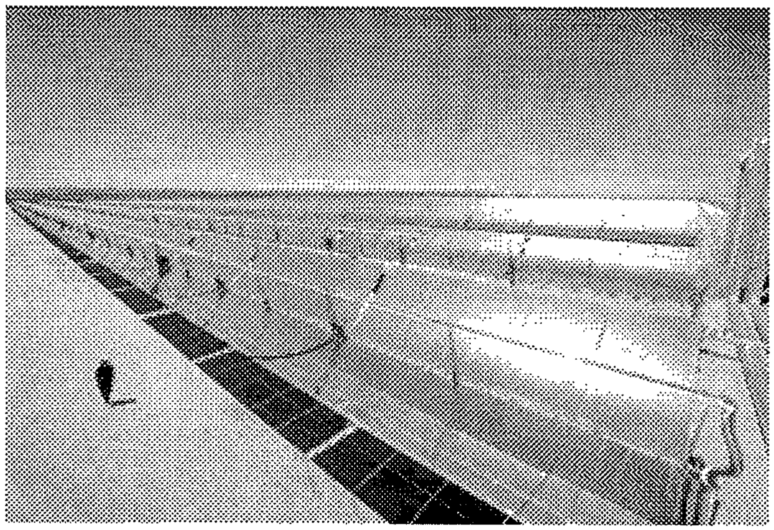
Concentrating solar power systems can be sized for distributed generation or grid-connected applications. Some systems use thermal storage during cloudy periods or at night. Others can be combined with natural gas and the resulting hybrid power plants provide high-value, dispatchable power. These attributes, along with high solar-to-electric conversion efficiencies, make concentrating solar power an attractive renewable energy option in the Southwest and other sunbelt regions worldwide.

Parabolic Trough Systems

Parabolic trough systems use mirrored surfaces curved in a parabolic shape that linearly extend into a trough shape. The collector focuses sunlight on a receiver pipe running the length of the trough along the inside of the curved surface. The sunlight heats the oil that is flowing through the pipe. The oil then goes to a heat exchanger where it either directly heats potable water or heats a thermal storage tank. As with all concentrating solar collectors, parabolic trough collectors use solar tracking systems that keep them facing the sun throughout the day, maximizing solar heat gain.

A collector field comprises many troughs in parallel rows aligned on a north-south axis. This configuration enables the single-axis troughs to track the sun from east to west during the day to ensure that the sun is continuously focused on the receiver pipes. Individual trough systems currently can generate about 80 MW of electricity. Trough designs can incorporate thermal storage -- setting aside the heat transfer fluid in its hot phase -- allowing for electricity generation several hours into the evening. Currently, all parabolic trough plants are "hybrids," meaning they use fossil fuel to supplement the solar output during periods of low solar radiation. Typically a natural gas-fired heater or a gas steam boiler/re-heater is used; troughs also can be integrated with existing coal-fired plants.

Figure 17: Parabolic Trough Solar Collector System



Source: Sandia National Laboratory

Power Tower Systems

Power tower systems use a large field of sun-tracking mirrors, called heliostats, to concentrate sunlight onto a receiver located on top of a tower. The energy heats fluid inside the receiver. Water has been used as the fluid, generating steam in the tower to drive a turbine to generate electricity. Molten salt has also been used. The salt's heat energy is then used to generate electricity in a conventional steam generator. The molten salt retains heat efficiently, so it can be stored for hours or even days before being used to generate electricity. Solar Two, a demonstration power tower located in the Mojave Desert in California, can generate about 10 MW of electricity.

The liquid salt at 550°F is pumped from a "cold" storage tank through the receiver, where it is heated to 1,050°F and then onto a "hot" tank for storage. When power is needed from the plant, hot salt is pumped to a steam generating system that produces superheated steam to power a turbine and generator. From the steam generator, the salt is returned to the cold tank, where it is stored and eventually reheated in the receiver. With thermal storage, power towers can operate at an annual capacity factor of 65%, which means they can potentially operate for 65% of the year without the need for a back-up fuel source. Without energy storage, solar technologies like this are limited to annual capacity factors near 25%. The power tower's ability to operate for extended periods of time on stored solar energy separates it from other renewable energy technologies.

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Figure 18: Central Receiver Solar Collector System

Source: Solar Two

Dish/Engine Systems

A dish/engine system is a stand-alone unit composed primarily of a collector, receiver and an engine. The sunlight is collected and concentrated by a dish-shaped surface onto a receiver that absorbs the energy and transfers it to the engine's working fluid. The engine converts the heat to mechanical power in a manner similar to conventional engines by compressing the working fluid when it is cold, heating the compressed working fluid, then expanding it through a turbine or with a piston to produce work. The mechanical power is converted to electrical power by an electric generator or alternator.

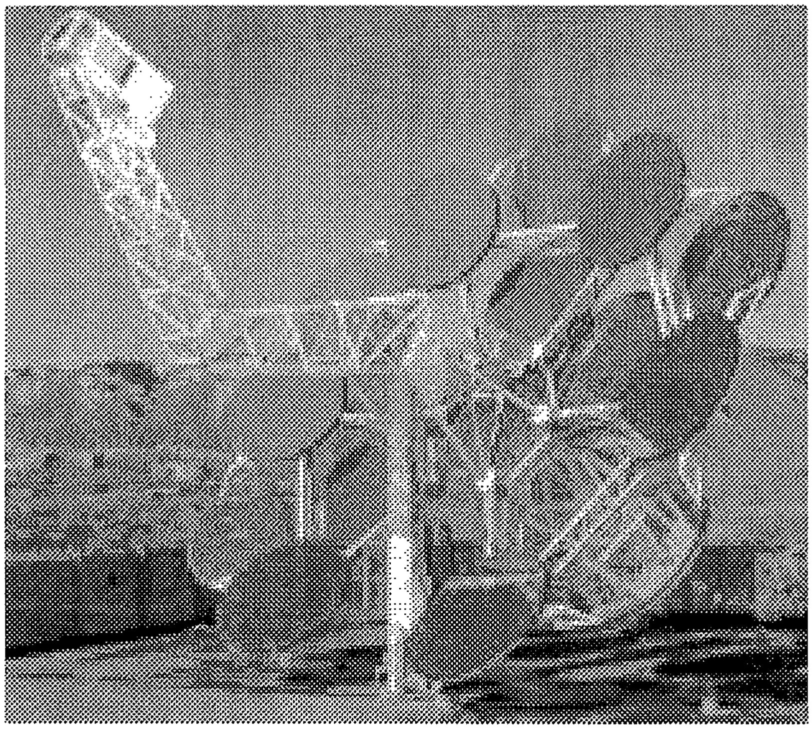
Many options exist for receiver and engine type, including Stirling (external combustion) engine and Brayton (gas turbine) engine receivers. Each engine has its own interface issues. Stirling engine receivers must efficiently transfer concentrated solar energy to a high-pressure oscillating gas, usually helium or hydrogen. In Brayton engine receivers the flow is steady, but at relatively low pressures.

A number of thermodynamic cycles and variations on the above cycles have also been considered. The use of conventional automotive Otto and Diesel engine cycles are not feasible because of the difficulties in integrating them with concentrated solar energy. Electrical output in the current dish/engine prototypes is about 25 kW for dish/Stirling systems and about 30 kW for the Brayton systems under consideration. Smaller 5 to 10 kW dish/Stirling systems have also been demonstrated.

There are two general types of Stirling receivers, direct-illumination receivers (DIR) and indirect receivers, which use an intermediate heat-transfer fluid. Directly-illuminated Stirling receivers adapt the heater tubes of the Stirling engine to absorb the concentrated solar flux. Because of the high heat transfer capability of high-velocity, high-pressure helium or hydrogen, direct-illumination receivers are capable of absorbing high levels of solar flux (approximately 75 W/cm). However, balancing the temperatures and heat addition between the cylinders of a multiple cylinder Stirling engine is an integration issue.

Solar receivers for dish/Brayton systems are less developed. In addition, the heat transfer coefficients of relatively low-pressure air along with the need to minimize pressure drops in the receiver make receiver design a challenge. The most successful Brayton receivers have used "volumetric absorption" in which the concentrated solar radiation passes through a fused silica "quartz" window and is absorbed by a porous matrix. This approach provides significantly greater heat transfer area than conventional heat exchangers that utilize conduction through a wall.

Figure 19: Dish/Engine Solar Collector System



Source: EREN

The size of the solar concentrator for a dish/engine system is determined by the engine. At a nominal maximum direct normal solar insolation of 1000 W/m, a 25-kW dish/Stirling system's concentrator has a diameter of approximately 10 meters. To track the sun, dish/engine systems use dual-axis collectors shaped as parabolas, created either by a single reflective surface or multiple reflectors. Concentrators use a reflective surface of aluminum or silver, deposited on glass or plastic. The most durable reflective surfaces have been silver/glass mirrors, similar to decorative mirrors used in the home. Because dish concentrators have short focal lengths, relatively thin-glass mirrors (thickness of approximately 1 mm) are required to accommodate the required curvatures. In addition, glass with a low-iron content is desirable to improve reflectance. Depending on the thickness and iron content, silvered solar mirrors have solar reflectance values in the range of 90 to 94%.

Tracking in two axes is accomplished in one of two ways, either with azimuth-elevation tracking or with polar tracking. In azimuth-elevation tracking, the dish rotates in a plane parallel to the earth and in another plane perpendicular to it. This gives the collector left/right and up/down rotations. Rotational rates vary throughout the day but can be easily calculated. Most of the larger dish/engine systems use this method of tracking. In the polar tracking method, the collector rotates about an axis parallel to the earth's axis of rotation. The collector rotates at a constant rate of 15°/hr to match the rotational speed of the earth. Most of the smaller dish/engine systems have used this method of tracking.

Of all solar technologies, dish/engine systems have demonstrated the highest solar-to-electric conversion efficiency (the Advanco Vanguard system, a 25 kW nominal output module, recorded a record 29.4% solar-to-electric conversion efficiency), and therefore have the potential to become one of the least expensive sources of renewable energy. The modularity of dish/engine systems allows them to be deployed individually for remote applications, or grouped together for small-grid or end-of-line utility applications.

Dish/engine technology is also the oldest of the solar technologies, dating back to the 1800s when a number of companies demonstrated solar powered steam-Rankine and Stirling-based systems. Modern technology was developed in the late 1970s and early 1980s by United Stirling AB, Advanco Corporation, McDonnell Douglas Aerospace Corporation (MDA), NASA's Jet Propulsion Laboratory, and DOE. MDA subsequently attempted to commercialize a system. Eight prototype systems were produced by MDA before the program was canceled in 1986 and the rights to the hardware and technology sold to Southern California Edison (SCE). SCE never brought the technology to the commercial market.

In the early 1990s, Cummins Engine Company attempted to commercialize dish/Stirling systems with support from SunLab, a Sandia National Laboratories and the National Renewable Energy Laboratory venture, through two 50/50 cost shared contracts. However, largely because of a corporate decision to focus on its core diesel-engine business, Cummins canceled their solar development in 1996.

Dish/engine systems can easily be used as distributed generation systems. While the power rating and modularity of dish/engine systems seem ideal for stand-alone applications, there are challenges related to installation and maintenance of these systems in a remote environment. Dish/engine systems need to stow when wind speeds exceed a specific condition, usually at about 16 m/s. Reliable sun and wind sensors are therefore required to determine if conditions warrant operation. In addition, energy storage with its associated cost and reliability issues is needed. Because dish/engine systems use heat engines, they have an inherent ability to operate on fossil fuels. The use of the same power conversion equipment, including the engine, generator, wiring, switch gear, etc., means that only the addition of a fossil fuel combustor is required to enable a hybrid capability. For dish/Brayton systems, addition of a hybrid capability is straightforward. A fossil-fuel combustor capable of providing continuous full-power operation can be provided with minimal expense or complication. For dish/Stirling systems, on the other hand, addition of a hybrid capability is a challenge. As a result, costs for Stirling hybrid capability are expected to be on the order of an additional $250/kW in large scale production.

Solar thermal dish/engine technologies are still considered to be in the engineering development stage. Assuming the success of current dish/engine joint ventures, these systems could become commercially available in the next 2 to 4 years. The primary R&D need for dish/engine technology is introduction of a commercial solar engine. Secondary R&D needs include a commercially viable heat-pipe solar receiver for dish/Stirling, a hybrid-receiver design for dish/Stirling, and a proven receiver for dish/Brayton. All three of these issues are currently being addressed as part of the DOE Solar Thermal Electric Program. The solar components are the high cost elements of a dish engine system, and improved designs, materials, characterization, and manufacturing techniques are key to improving competitiveness.

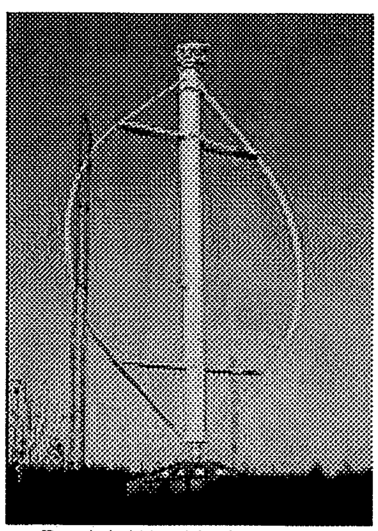
Wind

Wind power uses the energy in the wind for generating electricity. Large, modern wind turbines operate together on wind farms to produce electricity for utilities. Small turbines are used by homeowners and remote villages to help meet energy needs through distributed generation. Wind turbines can even be combined with a photovoltaic (solar cell) system. Stand-alone turbines are typically used for water pumping or communications. However, homeowners and farmers in windy areas can also use turbines to generate electricity. For utility-scale sources of wind energy, a large number of turbines are usually built close together to form a *wind farm.* Many electricity providers today use wind farms to supply power to their customers.

The large wind turbines found on wind farms require high wind resources because they must compete with conventional generation at the wholesale level. Wind energy potential increases very rapidly with increasing wind speed. If wind speed doubles, the energy content goes up eight fold. Small wind systems are used primarily for individual homes, businesses, or facilities -- on or off-grid. Though they cost relatively more (per kW) than large turbines, small wind turbines can be used in areas with modest wind resources because they compete at the retail level. The costs of small wind turbines has not dropped very much in the last 15 years, principally because small wind systems have not been granted the subsidies that are available for large wind turbines and solar modules. However, recent developments have given way to new subsidy programs for purchasers of small wind turbines and new technology. The future prospects for cost reductions in small wind turbines are the best they have been in twenty years. Typically, residential systems are 20-year investments.

Modern wind turbines are divided into two major categories: horizontal axis turbines and vertical axis wind turbines (VAWT). Horizontal axis turbines are the most common turbine configuration used today. They consist of a tall tower, atop which sits a fan-like rotor that faces into or away from the wind, the generator, the controller, and other components. Most horizontal axis turbines built today are two- or three-bladed, although some have fewer or more blades. Vertical axis turbines fall into two major categories: Savonius and Darrieus. Neither turbine type is in wide use today.

Figure 20: Darrieus Wind Turbine



Source: Danish Wind Industry Association

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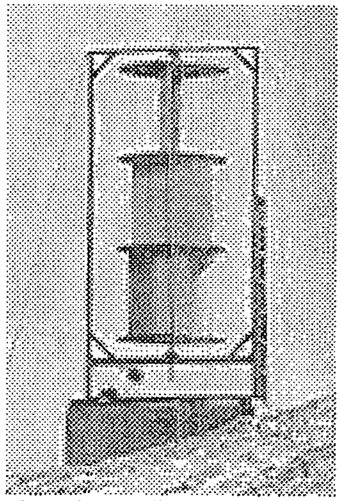
The Darrieus turbine was invented in France in the 1920s. Often described as looking like an eggbeater, this vertical axis turbine has vertical blades that rotate into and out of the wind. Using aerodynamic lift, these turbines can capture more energy than drag devices. The Giromill and cycloturbine are variants on the Darrieus turbine. First invented in Finland, the Savonius turbine is S-shaped if viewed from above. This drag-type VAWT turns relatively slowly, but yields a high torque. It is useful for grinding grain, pumping water, and many other tasks, but its slow rotational speeds are not good for generating electricity.

Figure 21: Savonious Wind Turbine



Source: American Wind Energy Association

Horizontal axis wind turbines capture the wind's energy with two or three propeller-like blades, which are mounted on a rotor, to generate electricity. The blades act much like an airplane wing. When the wind blows, a pocket of low-pressure air forms on the downwind side of the blade. The low-pressure air pocket then pulls the blade toward it, causing the rotor to turn. This is called lift. The force of the lift is actually much stronger than the wind's force against the front side of the blade, which is called drag. The combination of lift and drag causes the rotor to spin like a propeller, and the turning shaft spins a generator to make electricity.

Most turbines are designed for high reliability, low maintenance, and automatic operation in adverse weather conditions. Generally, they come in three configurations: battery charging, water pumping, and grid-connected. Battery charging turbines are supplied with outputs of 24, 48, 120 or 240 VDC. They are well suited for large rural homes, remote villages and facilities, eco-tourism resorts, and larger telecommunications sites.

Connected to the grid, turbines can provide most of the electricity for an average total electric home at moderate wind sites. Typical specifications are: 2 or 3-Blade Rotor with a diameter of approximately 7m (23 ft) utilizing a pitch-control center with overspeed protection and a direct-drive gear box. Turbines typically operate in temperatures between -40 to +60°C (-40 to +140°F). Typical start-up wind speed is 3.4m/s (7.5 mph); cut-in wind speed is 3.1m/s (7 mph); and a rated wind speed of 13m/s (29 mph) for a rated power of 10kW (grid & pumping), or 7.5kW for battery-charging. Furling wind speed is 15.6m/s (35 mph) with a maximum design speed of 54m/s (120 mph). These figures are for general calculations. With significant

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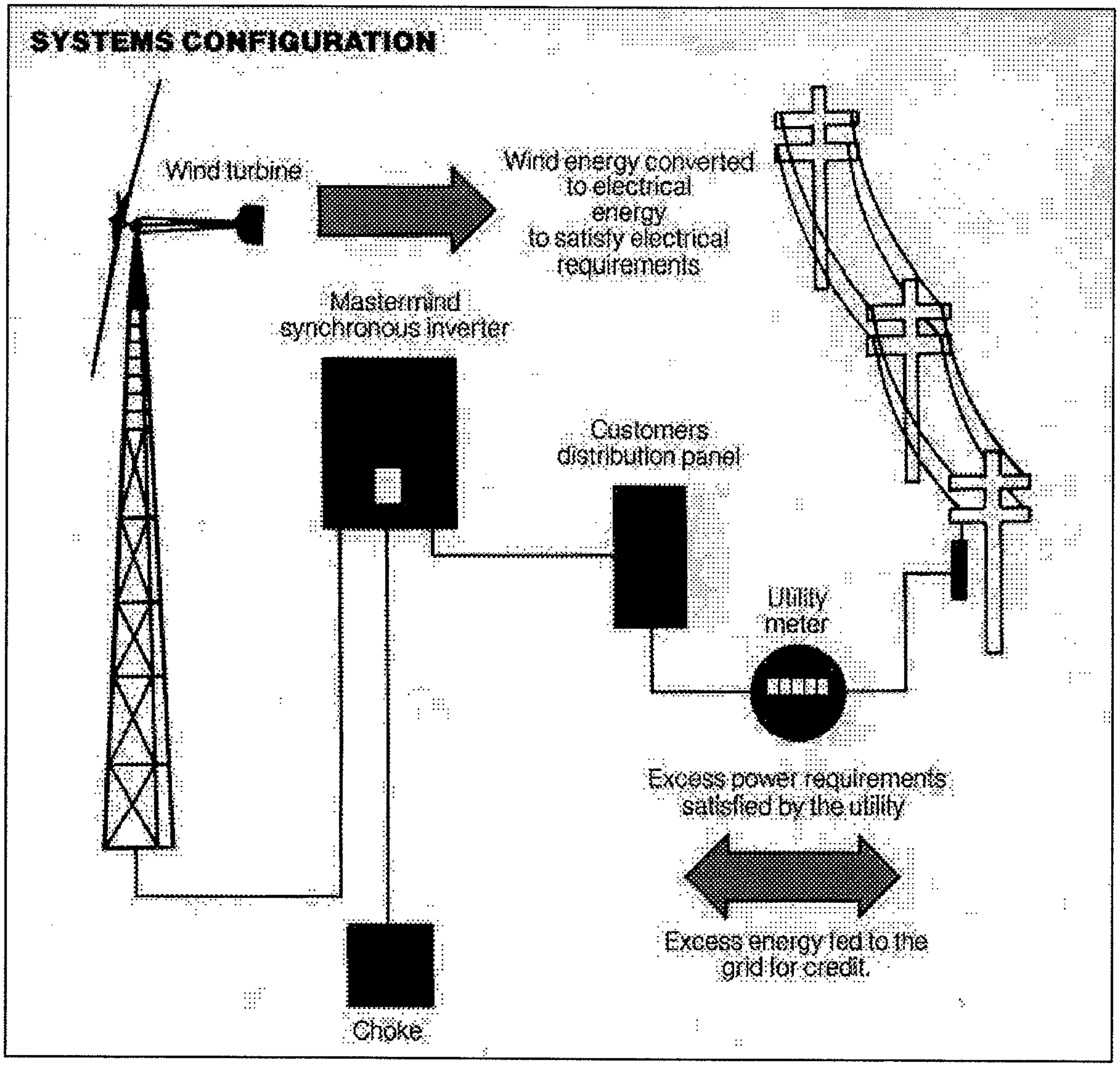
differences and modifications to the turbine designed to fit the customer's need, specifications change accordingly.

Figure 22: Wind Grid-Intertie Schematic



Wind speed generally increases with height above the ground. Taller towers expose turbines to stronger winds, enabling them to produce more electricity. Until now, the value of the extra electricity has been nearly offset by the cost of materials to make the towers bigger, at least for traditional steel lattice or tube towers. However, innovative tower designs are allowing taller towers to be built at reduced cost. Consequently, average tower height should gradually increase from 100 feet to about 230 feet by 2005.

Rotors are large, heavy, and crucial to capturing energy from the wind. Because improvements in rotor design have a great impact on energy costs, two national laboratories have looked into new designs for airfoils; innovative hub attachments that allow rotors to be more flexible; and improved manufacturing processes for blades.

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Airfoils specifically designed for turbine blades can greatly enhance turbine performance. Airfoils are the cross-sectional shapes on airplane wings or turbine blades that convert airflow into forces that can lift an airplane or turn a turbine rotor. Researchers have created seven "families" of airfoils for turbine blades of specific sizes. The new airfoils can increase energy capture by as much as 30% in constant-speed rotors.

Turbine rotors with two blades capture about the same amount of energy as their three-bladed counterparts and are much less expensive to build. However, two-bladed rotors must be flexible enough to respond to wind gusts and dissipate forces in the wind that would otherwise impact the turbine.

Sandia National Laboratory is striving to lower the cost of turbine rotors by working with industry to improve manufacturing of turbine blades. By improving manufacturing processes, shortening the time it takes to cure the blades, and making other improvements, researchers hope to reduce the blade costs by as much as 25%. Sandia is also working with industry and academia to improve blade-manufacturing processes for fiberglass and plastic blades.

The nacelle contains the key components of the wind turbine including the gearbox and generators. Service personnel may enter the nacelle from the tower of the turbine.

Today, most wind turbines use constant-speed generators to make electricity from the rotational energy produced when the wind turns the turbine rotor. These standard generators are widely available from industry. They are affordable but require costly transmissions and gears to operate. The gears increase the speed of the turbine rotor, which is 60 revolutions per minute (rpm) or less, to 1,800 rpm, the rotational speed required to operate a typical "off the shelf" generator.

The development of generators that work at low rotational speeds holds promise for better performance at lower cost. Because some generators can operate at the same rotational speeds as the turbine rotor, the expensive gearbox can be eliminated. Designing the generators is a major technical challenge, however. To work, low-speed generators require custom-made, high-efficiency, solid-state electronic converters, called power electronic converters, to generate 60-cycle alternating current and allow the generator to operate at variable speeds.

Researchers believe custom-made, low-speed generators with power electronics and variable-speed operation will be able to produce about 10% more electricity than their constant-speed counterparts. Because they can respond to changes in the wind, variable-speed generators can keep the turbine operating at maximum efficiency. Plus, they are quieter and reduce wear and tear on the turbine. In a constant-speed machine, rotor speed must be held steady and cannot increase once the turbine is producing maximum power. In a variable-speed machine, the rotor can spin faster in response to increases in wind speed, thereby using more of the power in the wind to generate electricity.

Variable-speed generators should work well with both standard, three-bladed machines and two-bladed, flexible turbines. Designing custom generators and power electronics that both work efficiently at low wind speeds is essential, however. Otherwise, poor performance at low wind speeds will offset some of the gains in efficiency at higher wind speeds.

In the past, turbine controls were used to solve particular problems: to slow or stop the rotor, to prevent wind gusts from suddenly producing too much power, to prevent the turbine from vibrating during operation, to mitigate damage from turbulent winds, and so on. A better way to control a wind turbine is via an electronic brain, or smart controller, which can optimize every aspect of turbine operation. Smart controllers use microprocessors to continuously evaluate wind conditions and turbine operation at any given moment. The controller then adjusts turbine operation to maximize the amount of power it generates, to protect the machine from excessive wear and tear, and to ensure maximum service life, low energy costs, and safe operation. Such a controller will ensure the maximum benefit from using light, flexible rotors and custom generators.

In the future, system control specialists will work on designing new turbines from the beginning. Understanding how a wind turbine works, they will be able to design smart control systems as an integral feature of the next generation of utility wind turbines. Computerized control systems can also help wind power plants run more efficiently. NREL's partner Second Wind, Inc. developed a sophisticated wind power plant control system. The system can monitor each turbine's power output as well as current wind conditions. Power plant operators can use this information to adjust the operation of individual turbines to maximize power output or minimize wear and tear on the machine. A supervisory computer also allows operators to see the entire power plant at one time by displaying a map of the turbines, meteorological towers, and substations. DOE is using Second Wind's power plant control system to monitor turbine performance in new projects being developed under the Wind Turbine Verification Program.

The wind turbine yaw mechanism is used to turn the wind turbine rotor against the wind. The wind turbine is said to have a yaw error, if the rotor is not perpendicular to the wind. A yaw error implies that a lower share of the energy in the wind will be running through the rotor area. If this were the only thing that happened, then yaw control would be an excellent way of controlling the power input to the wind turbine rotor. That part of the rotor which is closest to the source direction of the wind, however, will be subject to a larger force (bending torque) than the rest of the rotor. On the one hand, this means that the rotor will have a tendency to yaw against the wind automatically, regardless of whether we are dealing with an upwind or downwind turbine. On the other hand, it means that the blades will be bending back and forth for each turn of the rotor. Wind turbines, which are running with a yaw error, are therefore subject to larger fatigue loads than wind turbines, which are yawed, in a perpendicular direction against the wind.

Almost all horizontal axis wind turbines use forced yawing, i.e. they use a mechanism which uses electric motors and gearboxes to keep the turbine yawed against the wind. Almost all manufacturers of upwind machines prefer to brake the yaw mechanism whenever it is unused. The yaw mechanism is activated by the electronic controller which several times per second checks the position of the wind vane on the turbine, whenever the turbine is running.

Other Technologies

Stirling Engines

A stirling engine is in itself environmentally benign, however it's only considered a green technology if it's running on biomass, solar or some other green fuel. It is possible for stirling engines to run on fossil fuels, however when this is the case, they have harmful environmental affects and are not considered a green technology.

While stirling engine systems have most commonly been used in concentrating solar technologies, they have also been combined in such diverse applications as BioPower, gas-fired micro-cogeneration and waste heat energy generation. The most important aspect of the Stirling engine is the role it can play to enhance efficiencies. Especially in concentrating solar power system, the Stirling engine is essential.

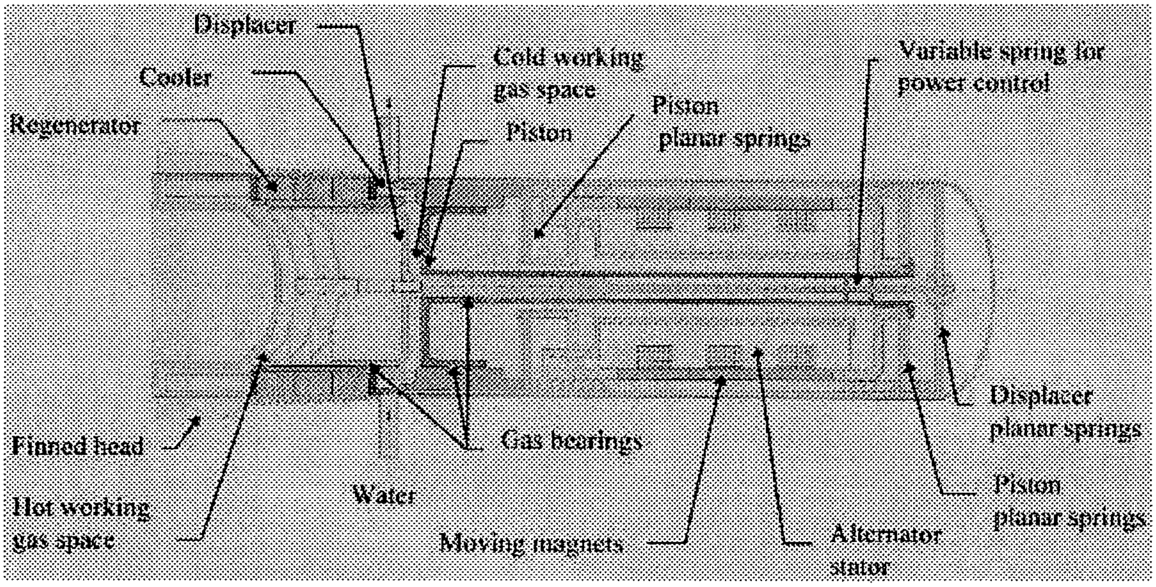
The Stirling engine is an external combustion engine that uses heat to expand a gas, usually air, but sometimes helium or hydrogen, hermetically sealed inside the cylinder, to move pistons which spin electricity generators. Typical reciprocating engines rely on internal combustion, which pumps fuel directly into the cylinder for combustion. Stirling engine technology has been around since 1816, but has not been used commercially for more than 50 years. The engine is named after a Scottish minister who invented it as an alternative to the early steam engine, which had a tendency to explode.

The crank-driven Stirling engine has a history of development, first as an air charged, atmospheric pressure pumping engine in the 1800's, and later, after World War II, as a highly refined candidate for automotive applications. In this role it was projected to be efficient, quiet and low in emissions. However, exceptionally challenging design problems were encountered, including power modulation, containment of high pressure light gas, isolation of lubricants, and cost and complexity of heater head designs able to accept the required high operating temperature and high heat fluxes. As a result of these and other barriers, especially the competition from cheap and ever-improving internal combustion engines, the crank Stirling has never reached commercial production.

The free-piston Stirling machine has evolved as a solution to the problems presented by the crank Stirling. Free-piston machines with an attached linear alternator can be hermetically sealed so as to contain the working gas (helium or hydrogen) for extended periods and they require no lubricant other than the working gas. Their power can be varied rapidly and efficiently by displacer amplitude and phase changes relative to the piston. Their high mechanical efficiency allows them to achieve competitive power and thermal efficiency at modest heater head temperatures consistent with relatively inexpensive materials and geometries. While free-piston machines are at present restricted in power output to several tens of kilowatts by the characteristics of linear alternators, the free-piston/linear alternator is quite well suited for the micro-cogeneration applications. These designs retain high efficiency and other desirable features over power ranges from a few tens of watts to several kilowatts, the desired power for micro-cogen.

The following illustration shows a typical layout of a free-piston Stirling engine. The thermodynamic cycle used is a harmonic oscillation approximation to the ideal Stirling cycle of two isotherms connected by two constant volume temperature changes. The piston oscillation causes the compression-expansion and the displacer serves to move the working gas between hot and cold heat exchangers to accomplish the heat flows required for the cycle.

Figure 23: Free-Piston Stirling Engine Diagram



Source: SunPower, Inc.

The piston and displacer are tuned as mechanical spring-mass-damper resonators so as to have the correct phase relation between them to accomplish the desired gas cycle. This method eliminates the crank mechanism and its associated lubrication and side forces. The engine operates at an approximately constant frequency regardless of loading or piston amplitude, which will permit it to be directly attached to the grid without intermediaries. The piston power is delivered directly to the magnets of a permanent magnet alternator to produce alternating current power at any desired voltage.

The life of free-piston Stirling machines has usually been limited by the contact bearings used to support the piston and displacer and the ring seals that separate the different gas volumes within the machines. Recent advances have removed both of these wear-limited components. Both piston and displacer float on gas bearings in their cylinders and are resonated by mechanical springs, which are arranged to eliminate side loads on the bearings. These planar springs (flat plates with spiral slits) also serve to center and support the large radial loads of the permanent magnets, acting in effect as friction-free oscillating bearings. The combination of gas bearings to allow wear-free close fits on the pistons and the use of mechanical springs to give both resonant frequency and axial positioning is uniquely advantageous in that it confers high mechanical efficiency and the potential for very long life. In addition, this combination is inexpensive and compact. The sealing function is also met by the close fits of the gas bearings, gas tight sealing is not needed, and the fits and tolerances can be met by standard machining techniques.

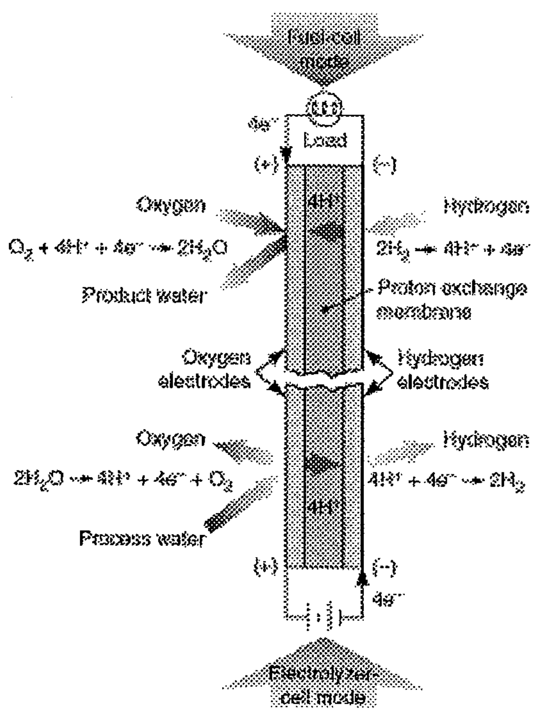
Fuel Cells

While not exactly a green power source, fuel cells have the potential to be an environmentally benign source of power in the future. Fuel cells are similar to stirling engines in that their status as a green power technology depends on the fuel that they are being powered with. Since there is no combustion in fuel cells, there are none of the pollutants commonly produced by boilers and furnaces. And for systems designed to consume hydrogen directly, the only products are electricity, water and heat. However, when hydrogen is extracted from natural gas or other hydrocarbons, fuel cells produce some carbon dioxide, and are no longer considered a green power technology.

A fuel cell consists of two electrodes -- a negative electrode (or anode) and a positive electrode (or cathode) -- sandwiched around an electrolyte. Hydrogen is fed to the anode, and oxygen is fed to the cathode. Activated by a catalyst, hydrogen atoms separate into protons and electrons, which take different paths to the cathode. The electrons go through an external circuit, creating a flow of electricity. The protons migrate through the electrolyte to the cathode, where they reunite with oxygen and the electrons to produce water and heat.

The are many types of fuel cells; however, the most promising as a future green power technology are regenerative fuel cells. Regenerative fuel cells work as a closed-loop form of power generation. Water is separated into hydrogen and oxygen by a solar-powered electrolyzer. The hydrogen and oxygen are fed into the fuel cell, which generates electricity, heat and water. The water is then recirculated back to the solar-powered electrolyzer and the process begins again. NASA and others are currently researching these types of fuel cells worldwide.

Figure 24: Regenerative Fuel Cell Process



Source: Lawrence Livermore National Laboratory

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Economic Overview Of Technologies

BioPower

The cost to generate electricity from biomass depends on the type of technology used, the size of the power plant, and the cost of the biomass fuel supply. BioPower systems range in size from a few kW up to 80 MW power plants. Co-Firing systems can result in payback periods as low as 2 years. The levelized cost depends on the type of plant. In today's direct-fired biomass power plants, generation costs are about 9¢/kWh. In the future, advanced technologies such as gasification-based systems could generate power for as little as 5¢/kWh. In co-firing, biomass fuel can cost less than coal when low cost biomass fuels are used; modifications to the coal plant can have payback periods of 2-3 years. According to the DOE, a typical existing coal fueled power plant produces power for about 2.3¢/kWh. Co-Firing inexpensive biomass fuels can reduce this cost to 2.1¢/kWh. For comparison, a new combined-cycle power plant using natural gas can generate electricity for about 4 to 5¢/kWh depending on the price for natural gas.

For biomass to be economical as a power plant fuel, transportation distances from the resource supply to the power generation point must be minimized, with the maximum economically feasible distance being less than 100 miles. The most economical conditions exist when the energy use is located at the site where the biomass residue is generated (i.e., at a paper mill, sawmill, or sugar mill). Modular BioPower generation technologies under development by the DOE and industry partners will minimize fuel transportation distances by locating small-scale power plants at biomass supply sites.

Most analysts believe that the economics of BioPower will improve as larger plants are constructed with higher efficiencies. Increasing efficiency is the key to lowering the overall costs of BioPower.

Geothermal

Geothermal energy development typically involves some risk in the initial investigations to prove the geothermal resource. Investment is required for exploration, drilling wells, and installation of the plant, but operating costs are very low because of the low cost of fuel. In comparison, fossil fuel power plants have significantly cheaper start-up costs, but fuel costs are much higher.

Geothermal development project capital costs are very much site and project specific. The following table shows direct capital cost for small, medium and large plants developed in high, medium and low quality geothermal resources. A high quality geothermal energy resource is taken to mean a resource with high temperature, very good field wide permeability (and therefore high well productivity), low gas content, and benign chemistry. A low quality resource is one with reservoir temperature below 150°C, or a resource that has poor permeability, high gas content and difficult chemistry. The exploration phase is made up of surface exploration and one to five exploration wells, each well costing about $1.5 million.

Indirect costs vary depending on the location of the site, its accessibility and level of infrastructure. In a typical project site in a developed country where infrastructure is in place, skilled labor is available, and port facilities and a major city relatively close by the indirect cost are approximately 5-10% of direct costs. In a location in a more remote area of a developed country, or in an area of a developing nation where infrastructure is good, there is skilled labor and the nation enjoys political and social stability, indirect costs are about 10-30% of direct costs. In a remote area of a developing nation where infrastructure is poor, accessibility is difficult, skilled labor is scarce and there is the risk of political instability, indirect costs are about 30-60% of direct costs.

Table 3: Direct Capital Costs of Geothermal Energy ($/kW installed capacity)

Plant Size	High Quality Resource	Medium Quality Resource	Low Quality Resource
Small plants (<5 MW)	Exploration: $400-800 Steam field: $100-200 Power plant: $1100-1300 *Total: $1600-2300*	Exploration: $400-1000 Steam field: $300-600 Power plant: $1100-1400 *Total: $1800-3000*	Exploration: $400-1000 Steam field: $500-900 Power plant: $1100-1800 *Total: $2000-3700*
Medium plants (5-30 MW)	Exploration: $250-400 Steam field: $200-500 Power plant: $850-1200 *Total: $1300-2100*	Exploration: $250-600 Steam field: $400-700 Power plant: $950-1200 *Total: $1600-2500*	Normally not suitable
Large plants (>30 MW)	Exploration: $100-200 Steam field: $300-450 Power plant: $750-1100 *Total: $1150-1750*	Exploration: $100-400 Steam field: $400-700 Power plant: $850-1100 *Total: $1350-2200*	Normally not suitable

Source: The World Bank Group

The DOE's Geothermal Energy Program continues to support the geothermal industry with research and development to reduce costs and help geothermal energy fulfill its potential. One major objective of the program is to reduce the levelized cost for geothermal electric power generation from the current $0.05 to $0.08 per kWh to $0.03 to $0.05 per kWh by 2007.

Ocean

Ocean technology is in the research and development stage and has yet to significantly enter the market. Therefore, price per kilowatt-hour is not adequately defined. There are several ocean technologies in place and generating electricity, and market opportunities have been studied. Depending on the technology, the price and capacities differ.

Tidal Electric, Inc. has estimated that capital costs will vary from site to site due to variations in the cost and availability of materials. Also, the larger the project, the smaller the capital costs per unit capacity. Thus, bigger projects will be more economical than smaller projects. At 100 MW, Tidal Electric estimated the capital costs be $1200 to $1500 per kilowatt capacity. Operating costs are minimal at $.005 per kWh. These estimates are for tidal projects only.

Like tidal power plants, Ocean Thermal Energy Conversion (OTEC) power plants require substantial capital investment upfront. OTEC is inherently a large-scale technology. The size of the investment dictates that, even though the process requires no fuel and will have relatively low operating costs, the investment will only be recouped over a number of years. The economic viability of OTEC is thus determined by factors such as the financing cost, the plant life-cycle and the future cost of competing energy sources. If an OTEC plant could be guaranteed to operate for 30 years without major overhaul, conservative projections of energy cost and interest rates predict a 30% return on investment. However, it is not possible to predict the life cycle of a 50 MW plant from the limited intermittent operation of a large plant, the 250 kW open cycle experiment at the Natural Energy Laboratory of Hawaii Authority (NELHA). World Bank advisors have determined that a pilot plant of about 5 MW operating for 5 years would be needed to justify investment in the full-scale technology. Such a plant would be very expensive.

Solar

Solar power has seen significant cost decreases over the past decade. Moreover, the technology is advancing. For the Sacramento Municipal Utility District (SMUD), which has the largest distributed utility PV system in the world, the PV system average cost (1996 dollars) per watt has fallen from $79 in 1975 to $11.88 in 1990, to $4.90 in 1998 and to $3.65 in 2000.[3]

The concentrating solar power industry has a decade-long performance record, one that can substantiate current and projected energy costs. This performance is with trough plants, the most mature of the three concentrating solar power technologies. Because they are hybrid plants that operate on natural gas during cloudy periods, trough plants underscore the potential for concentrating solar power technologies to combine with fossil fuel technology to take advantage of market opportunities. The combined efforts of industry and the DOE have reduced photovoltaic system costs by more than 300% since 1982. The photovoltaic market is estimated to be growing at 20-25% per year today. The number of U.S. companies producing photovoltaic panels has more than doubled since the late 1970s.

Concentrating solar power technologies currently offer the lowest-cost solar electricity for large-scale power generation (10 MW and above). Current technologies cost $2–$3 per watt. This results in a cost of solar power of 9¢–12¢/kWh. At this price, solar power is currently too expensive to compete in North America's bulk power markets; but it can compete in certain high-value and niche market -- for example, peak power. As the technology develops, costs will decrease further and new markets will open. New innovative hybrid systems that combine large concentrating solar power plants with conventional natural gas combined cycle or coal plants can reduce costs to $1.5 per watt and drive the cost of solar power to below 8¢/kWh. The following chart summarizes unit capacity, capital costs, operational and maintenance costs, and current and projected levelized costs for the three solar concentrating technologies.

Table 4: Concentrating Solar Power Projected Cost

Technology and Status	Unit Capacity	Capital Cost ($/kW)	O&M (¢/kWh)	Levelized Cost (¢/kWh)	
				2000	2010
Troughs: Early Commercial	30-80 MW	2,900	1.0	6.8 - 11.2	5.6 - 9.1
Power Towers: Feasibility	30-200 MW	2,400 -2,900	0.7	5.2 - 8.6	3.3 - 5.4
Dish/Engines: Feasibility	5-50 kW	2,900	2.0	8.6 - 13.0	4.0 - 6.0

Source: EREN

[3] Energy Information Administration, Renewable Energy 2000

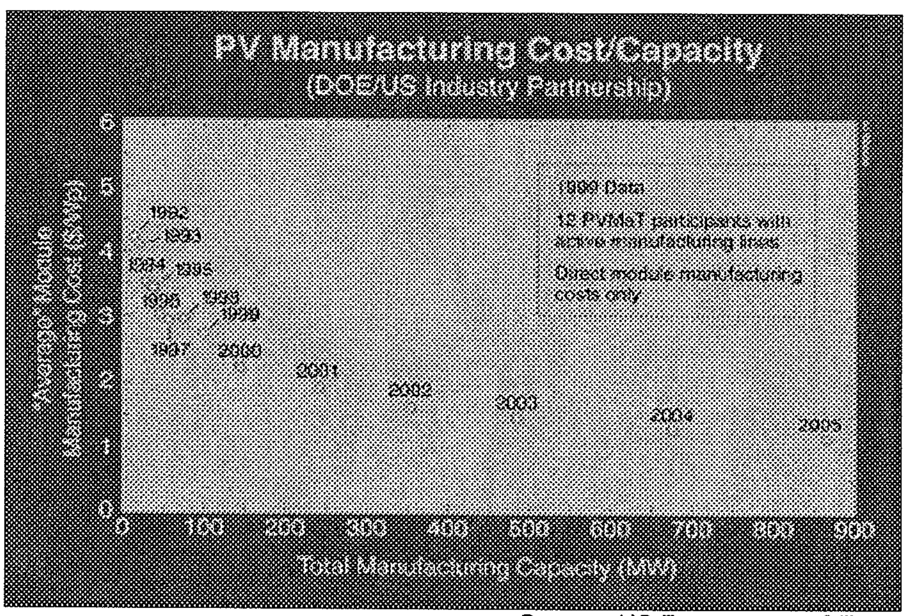
Advancements in the technology and the use of low-cost thermal storage will allow future concentrating solar power plants to operate for more hours during the day and shift solar power generation to evening hours. Future advances are expected to allow solar power to be generated for 4¢–5¢/kWhr in the next few decades.

Capital costs for solar technologies are higher than conventional power technologies, and operating costs are lower. Because capital costs must be amortized over the lifetime of the plant, project financing, interest rates, and tax policy heavily influence a solar project developer. As a result, the solar power industry is looking to compete in regions where policy stimulates developments such as enterprise zones, distributed generation, and niche markets.

The most recent bid at the Sacramento Municipal Utility District (SMUD) was less than $5 per watt. Several years ago, the community of Sacramento decommissioned its large nuclear power plant and decided to meet electricity demand requirements with efficiency and green power. The continued decline in SMUD's purchase costs reflects the buying advantage of large-volume annual purchases. One of the main reasons for solar becoming competitive is the manufacturing cost of cells has come down in the past decade.

The figure below shows total manufacturing capacity versus average direct costs for module manufacturing. The plot is based on data from twelve industrial participants who have active production lines. The value of "average module manufacturing costs" is a weighted average based on the manufacturing capacity of each of these participants.

Figure 25: PV Manufacturing Cost Trends



Source: US Department of Energy

As shown, photovoltaic manufacturing capacity has increased by more than a factor of seven since 1992. Additionally, the weighted-average cost for manufacturing photovoltaic modules has been reduced by 36% -- from $4.23 to $2.73 per peak watt. Projections through 2005, which include continuing R&D, indicate a steady decline to an average module manufacturing cost of $1.16 per peak watt at 865 MW by 2005.

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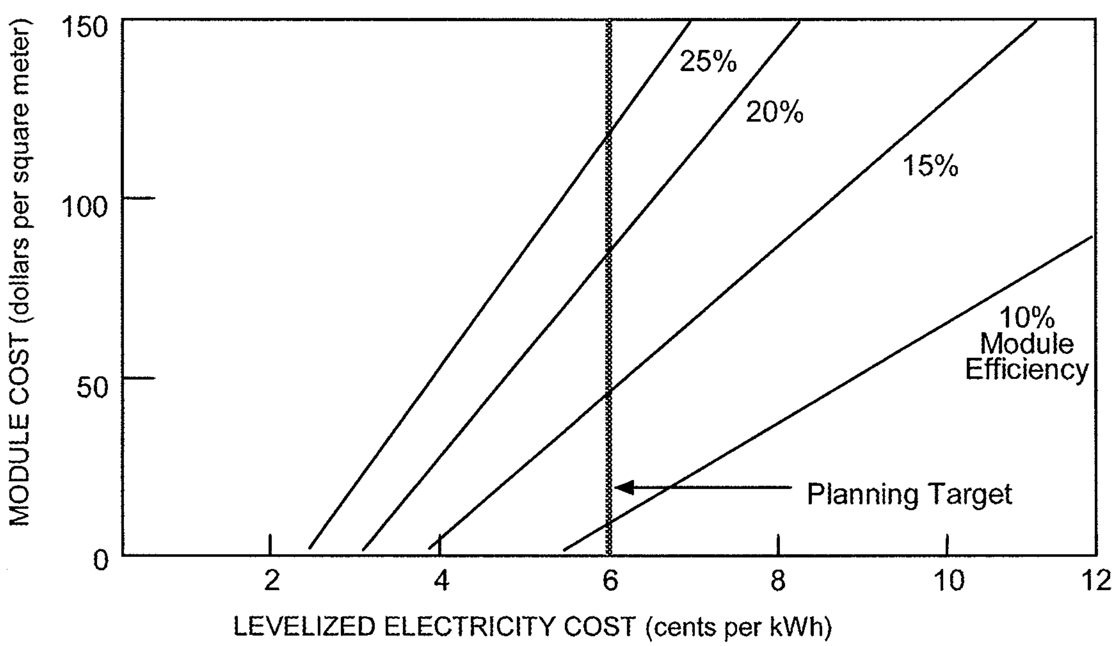
A number of factors influence PV energy costs. Foremost are module efficiency, lifetime and cost per unit area. The DOE has chosen a target of 6¢/kWh for its terrestrial PV program. The following chart indicates the interrelationships of cost and module efficiency that lead to specific electricity costs, given a 30-year lifetime for the module and making a number of economic assumptions.

From these curves it is clear that lower-efficiency modules have to cost less than higher-efficiency modules to produce the same cost of electricity. Hence there is a premium on higher efficiency. Similar curves exist for concentrator systems, but higher efficiencies are required to offset the higher balance-of-system costs associated with the necessary lenses or mirrors and sun trackers. In both cases, efficiency can be traded off against area-related costs (such as land, wire and support structure) to achieve the same cost of electricity.

Figure 26: PV Cost vs Efficiency



Wind

The average cost of electricity from wind energy has dropped from 50 cents per kWh in 1980 to 5 cents per kWh in 2001 in favorable wind regimes. Utility-scale wind turbines today usually have an installed cost of about $800 - $1,200 per kW. Smaller turbines tend to be twice as expensive per kW. The cost of electricity from utility-scale wind systems has dropped by more than 80% over the last 20 years.

Wind energy is making steady progress on economic cost, the most important criterion for future market success. Long-term forecasts by Pacific Gas & Electric and EPRI that wind would ultimately become the least expensive electricity generation source are on the way to being realized. Based on its knowledge of current market conditions, the American Wind Energy Association estimates the levelized cost of wind energy as ranging from 4.0 to 6.0 cents per

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kWh, not including the federal production tax credit. The credit (1.5 cents/kWh) applies to the first 10 years a new wind plant operates, and reduces the cost of wind by about 0.7 cents/kW over the plant's 30-year lifetime. This puts wind's costs in a competitive range with coal and gas on a 30-year levelized basis. Two additional points about wind's economics are important to understand:

First, the cost of wind is strongly affected by two factors, average wind speed and interest rates. Since the energy the wind contains is a function of the cube of its speed, small differences in average winds from site to site mean large differences in production and, therefore, in cost. Also, like hydro, wind is a capital-intensive technology; there is no fuel cost for a wind plant, so most of its cost is in the capital required for equipment manufacturing and plant construction. This in turn means that wind's economics are highly sensitive to the cost of capital. One study found that if wind plants were financed on the same terms as gas plants, their cost would drop by nearly 40%.

Second, wind is a new technology, and its cost is dropping faster than the cost of conventional generation. While the cost of a new gas plant has fallen by about 33% over the past decade, the cost of wind has dropped by 45% during the same period. Wind power today costs only about one-fifth as much as in the mid-1980's, and its cost is expected to decline by another 35-40% by 2006. Therefore, although most wind projects to date have been modest in size and driven by government incentives or other policies, the first decade of the new millennium should see it entering the generation market on a steadily increasing scale.

The cost of a wind system has two components: initial installation costs and operating expenses. The initial installation cost includes the purchase price of the complete system (including tower, wiring, utility interconnection or battery storage equipment, power conditioning unit, etc.) plus delivery and installation charges, professional fees and sales tax. The total installation cost can be expressed as a function of the wind system's rated electrical capacity. For example, a grid-connected residential-scale system (1-10 kW) generally costs between $2,400 and $3,000 per installed kW. That's $24,000-$30,000 for a 10 kW system. A medium-scale, commercial system (10-100 kW) is more cost-effective, costing between $1,500 and $2,500 per kilowatt. Large-scale systems of greater than 100 kW cost in the range of $1,000 to $2,000 per kilowatt, with the lowest costs achieved when multiple units are installed at one location. In general, cost rates decrease as machine capacity increases.

The other cost component, operating expenses, is incurred over the lifetime of the wind system. Operating costs include maintenance and service, insurance and any applicable taxes. A rule of thumb estimate for annual operating expenses is 2% to 3% of the initial system cost. Another estimate is based on the system's energy production and is equivalent 1 to 2 cents per kWh of output. Most wind turbines are designed to last for 20 years, however the actual life of a wind turbine depends on the quality of the turbine and the local climatic conditions.

These costs will be recouped after a payback period, which can be calculated by dividing the total initial cost by the difference between annual energy-cost savings and annual operating costs. The simple payback method does not account for all the actual costs and savings associated with a wind turbine investment over its operating lifetime. Additional costs and savings might include increases in energy costs relative to general inflation, interest paid on borrowed money, insurance, utility buy-back, state and federal tax benefits and the wind turbine's resale value. To an extent, these items can offset one another, depending on your particular circumstance. To determine the impact of one or more of the above factors on your investment, it is necessary to perform a life-cycle cost analysis. This comprehensive method

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calculates the wind system value by considering all the costs and savings on a yearly basis throughout a wind turbine's lifetime, and discounting them back to a present value. For most applications, the payback year estimated by this method will be fairly close to that estimated by the "simple" method.[4]

[4] Iowa Energy Center, Wind Energy Economics.

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Growth Potential for Green Power

Country Projections

Worldwide, renewable energy use is expected to increase by 53 percent between 1999 and 2020, or 2.1% per year, according to the U.S. Energy Information Administration (EIA). However, its current 9 percent share of total energy consumption is projected to drop slightly to 8 percent by 2020. Over this period, growth in renewable energy resources is expected to continue to be constrained by relatively moderate fossil fuel prices.

In the developing world, particularly in countries of developing Asia, such as China, India, Malaysia, and Vietnam, much of the growth in renewable energy use is driven by the installation of large-scale hydroelectric power plants. In the industrialized world, non-hydroelectric renewable energy sources are projected to predominate, particularly wind power in Western Europe and biomass and geothermal power in the United States.

According to the EIA, renewable energy use in North America as a whole is projected to increase by 1.4 percent per year between 1999 and 2020. Although Canada has announced some plans to expand its hydroelectric capacity over the next decade, hydropower consumption is expected to remain flat or decline slightly over the projection period for the region. Increases are expected for geothermal, wind, solar, biomass, and municipal solid waste (MSW) energy use.

Non-hydroelectric renewables are expected to account for 3.9 percent of all projected additions to U.S. generating capacity between 2000 and 2020. Generation from geothermal, biomass, landfill gas, solar, and wind energy is projected to increase from 77 billion kilowatt-hours in 1999 to 160 billion kilowatthours in 2020. Biomass (which includes cogeneration and co-firing in coal-fired power plants) is expected to grow from 38 billion kilowatthours in 2000 to 64 billion kilowatthours in 2020. Most of the increase is attributed to cogenerators, with a smaller amount from co-firing. Few new dedicated biomass plants are expected to be constructed over the forecast period.

High-output geothermal capacity could increase by 87 percent over the next two decades, to 5,300 megawatts, and could provide almost 35 billion kilowatthours of electricity generation by 2020. This will depend, however, on the success of several new, untested sites. Wind capacity in the United States is projected to grow by nearly 300 percent from 2,400 megawatts in 2000 to 9,100 megawatts by 2020. State mandates are expected to have the greatest impacts on renewable capacity additions in Texas (2,279 megawatts), California (1,930 megawatts), Nevada (1,148 megawatts), and New Jersey (904 megawatts), and smaller increases are expected in Massachusetts, Minnesota, Iowa, Wisconsin, and Arizona.

At present, 60 percent of Canada's total installed electricity generation capacity consists of hydroelectric dams. Canada is exploring ways to increase its hydroelectric capacity still further with several proposals that are currently under consideration. In the Northwest Territories there are proposals to develop hydroelectric projects that would total between 12,000 and 15,000 megawatts. At the end of 2000, there was an estimated 137 megawatts of total installed wind capacity in Canada. In order to spur further development, Canada has implemented a wind power production incentive. Wind projects installed between April 1, 2002, and March 31, 2007, will be eligible for a government incentive payment of about 0.8 cents per kilowatthour of generation. The payment will gradually decline to 0.5 cents per kilowatthour.

In Mexico there are limited plans to expand the renewable energy resource base at the present time. Mexico has made some moves toward increasing the development of geothermal resources, including studies by the state-owned Comisión Federal de Electricidad (CFE) and a government pledge to invest some $31 million in geothermal energy. There has been little activity in wind power development in Mexico, although by some estimates Mexico has wind resources that could support the installation of up to 5,000 megawatts of wind power capacity. The country has about 3 megawatts of installed wind capacity but has not added any new capacity since 1998. Construction of a 54-megawatt wind power project proposed by CFE in 1996 has continued to be postponed. In addition, five other wind projects proposed by private companies are still being negotiated. Construction permits have been issued to four of the five projects, but no construction work has been started.

Expansion of renewable energy sources in Western Europe is expected to be mostly in the form of non-hydroelectric renewables. Most potential hydroelectric resources have already been developed in the region, and there are few plans to extend hydropower capacity over the next two decades. Among the other forms of renewable energy, wind has made the greatest gains over recent years and will probably contribute to much of the future growth in renewable energy use. installations. The EU has moved to increase the penetration of renewables in the European energy mix. In 2001, the European Parliament approved a Renewables Directive that would require the EU to double the renewable share of total energy consumption by 2010. According to the new law, the share of total inland energy consumption met by renewable energy resources will have to increase to 12 percent in 2010, from an estimated current level of about 6 percent. Furthermore, the share of electricity demand met by renewables will have to increase to 22 percent, from about 14 percent now.

Of all the renewable energy sources, wind is the most promising in Europe. Germany, Spain, and Denmark have been among the world's top wind capacity installers in recent years, and in 2000 Italy and the United Kingdom also saw sharp increases in wind power capacity installations. Denmark added 588 megawatts of wind capacity in 2000, twice as much new capacity as it has installed in recent years. Under the government's Energy 21 strategy, the national target is to have 1,500 megawatts of wind power installed by 2005 and 5,500 megawatts by 2030.

Even some European countries that have been slow in developing wind programs heretofore are beginning to make plans for expanding this renewable energy source. Offshore wind is allowing European countries that do not have the land area to devote to wind turbines a chance to begin exploiting wind energy. There are also some plans to expand solar power in Western Europe. In anticipation of future growth in solar energy, BP Solar committed to constructing Europe's largest solar equipment manufacturing plant in Spain in 2001. The plant will be able to produce 60 megawatts per year of high-efficiency solar cells (with an aim to expand that amount to 100 megawatts). end of 2002.

Between 1999 and 2020, the use of hydroelectricity and other renewables is projected to increase by 1.4 percent per year in the region of Australasia (which includes Australia and New Zealand, along with the U.S. Territories). Much of this modest increase is expected to be in the form of non-hydroelectric renewables, most notably wind.

On December 21, 2000, the Australian government passed the Renewable Energy (Electricity) Act 2000 in an effort to encourage renewable energy development. The legislation, enacted on April 1, 2001, sets mandatory targets for renewable energy. It requires wholesale purchasers of electricity to contribute to the generation of an additional 9,500 gigawatthours of renewable

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energy each year by 2010. Interim targets are to be enforced, and penalties are to be assessed against electricity purchasers who do not attain their individual targets.

Support for the construction of large-scale hydroelectric dams remains strong in many countries of developing Asia, and large-scale hydropower projects in China, India, Malaysia, and Vietnam, among others in the region, are expected to provide most of the 4.3 percent annual growth in renewable energy consumption worldwide forecast. There are more modest efforts to increase non-hydroelectric renewable energy use, primarily wind and solar, in China, India, and other developing Asian countries, as well as generation from biomass in Bangladesh. The projects are often aimed at reaching small, rural communities that would otherwise not have access to electricity through the national grid.

Beyond the expansion of large-scale hydropower, several other projects are underway to develop China's other renewable resources, notably, wind and solar. The Global Environment Facility (GEF) and the World Bank have begun a 10-year project to increase China's non-conventional renewable energy use by 14,300 megawatts by 2010. The goal of the China Renewable Energy Scale-Up Program (CRESP) is to begin to reduce China's dependence on coal-fired electricity, as well as to bring electrification to the remote, rural parts of China that do not have access to the national grid.

India continues to encourage the development of renewable energy sources beyond hydroelectricity. In 2002, Indian Prime Minister Atal Bihari Vajpayee stated he would like renewable energy to account for at least 10,000 megawatts of the 100,000 megawatts of new electricity capacity to be added between 2001 and 2012.

The renewable resources that would be counted in this plan are small hydroelectricity, wind, solar, and bi-mass. The government expects that up to 2,000 megawatts of new wind capacity could be added to the current 1,340 megawatts before 2007, with biomass contributing 1,000 megawatts, small hydropower 800 megawatts, solar thermal 140 megawatts, waste-to-energy 100 megawatts, and grid-connected solar photovoltaic 15 megawatts. In recent years, bagasse (crushed sugar cane) cogeneration potential in cooperative and public-sector sugar mills has looked promising. Currently India has about 213 megawatts of installed bagasse cogeneration capacity, and another 263 megawatts is under construction at 29 plants.

In 2001, the Malaysian government announced that it would like renewable energy to account for 5 percent of total power generation by 2005. The government hopes to support the development of renewables with its new Small Renewable Energy Power (SREP) program. Under the program, small power producers using renewable energy will be given a license for a 21-year period (from the date by which a plant is commissioned) to sell their power through the national power grid. The renewable energy sources permissible under the SREP program include biomass, biogas, municipal waste, solar, mini-hydro, and wind. While the plant size can be greater than 10 megawatts, the maximum capacity for power exports to the national distribution grid cannot exceed 10 megawatts.

Hydroelectricity is an important source of electricity generation in Central and South America. (In Brazil, the region's largest economy, hydropower typically supplies more than 90 percent of the country's electricity generation.) As a result, drought can have a devastating impact on electricity supply, and many countries of Central and South America are initiating projects to diversify the mix of electricity supply.

The government of Brazil is working to develop non-hydroelectric renewables, especially in remote areas of the country that do not have access to the electricity grid. In 1998, the country started the National Program for Energy Development of States (PRODEEM) in an effort to install 20,000 megawatts of renewable energy capacity, with an investment of about $25 billion in photovoltaic and other renewable energy technologies. The project's aim was to expand electricity capacity through hundreds of community projects -- each expected to reach about 200 people living in rural communities that would not be connected to an expanding electricity grid before 2003. In addition to photovoltaics, the PRODEEM program included aero-generators and wind turbines, small central hydroelectric plants, biomass-derived fuels (alcohol, vegetable oils, forest and farm wastes), and biodigesters. Brazil is now launching a successor program to PRODEEM called ALVARADO, which will focus on increasing access to electricity in the northeastern part of the country. Starting in 2002, ALVARADO is expected to begin establishing small renewable energy systems. Like PRODEEM, ALVARADO will involve both local and international private-sector developers in its effort to install off-grid renewable energy projects. Another Brazilian scheme to promote the development of renewable energy resources involves electricity produced from sugar cane. The second-largest distributor of electricity in São Paulo state, CPFL, has set a target to increase its marginal power purchases from sugar cane industries to 7 percent of its total demand by 2003. Further, the Pernambuco state power company (owned by Spain's Iberdrola) has agreed to purchase all the electricity that is produced by the Cruangi sugar refinery through 2006.

Chile's National Energy Commission is planning to implement several projects that will involve non-hydroelectric renewable energy resources. The government has passed legislation promoting the development of 120 new geothermal projects by independent power producers. The National Electricity Commission has initiated an aggressive rural electrification program aimed at providing electricity to communities that lack access to the national electricity grid. Since 1992, Chile has invested $112 million in the program, which is expected to run until 2004, with the goal of supplying electricity to 100 percent of the population.

Other Central and South American countries are also attempting to address the problem of getting electricity to remote, rural areas. Costa Rica has one of the most ambitious programs for renewable energy in Latin America. The country instituted a policy mandating that by 2025 all forms of energy consumed in the country be derived from renewable sources. course. In Argentina, the government and the World Bank are implementing a project that is to provide electricity to roughly 70,000 rural households and 1,100 provincial public service institutions, principally through the use of renewable energy systems. Energy sources will be principally photovoltaic and wind, with biomass used to make up any shortfalls. Argentina has expressed a particular interest in developing its wind resources. The country has passed legislation that requires all utilities to purchase wind power if it is available. This should help cover the costs of building the necessary transmission infrastructure from the wind turbines to the power distributors. Further, with approval of the Argentine government, Spanish companies Endesa and Elecnor are developing 3,000 megawatts of wind energy capacity, to be completed by 2010.

There are only a few plans to expand the use of renewable resources in the countries of Eastern Europe and the former Soviet Union. In general, renewables are not competitive in the FSU, where fossil fuel resources are abundant and demand for clean forms of electricity can be met with cheaper natural-gas-fired capacity. FSU renewable energy demand is projected to increase by 1.6 percent per year. In Eastern Europe, the growth rates projected for hydroelectricity and other renewables are twice those for the FSU at 3.5 percent per year, reflecting the relatively small amount of renewable capacity currently installed in the region. In

2001 there were some modest attempts to increase the use of non-hydroelectric renewables in a few countries of the FSU. In July, Ukraine's parliament passed the Ukrainian Wind Power Development Project in an attempt to encourage the development of wind power and make wind power a "significant source" of electric power by 2020. Ukraine has extensive wind resources, although the development of a wind power industry would require technological and financial support. A Malaysian company, Ideal Fortune Holdings Sdn. Bhd., has been awarded a 25-year concession to build, own, operate, and transfer wind and hydroelectric power projects in Kazakhstan. A combined capacity of 500 megawatts is to be added in Kazakhstan.

In Africa and the Middle East, hydroelectricity and other renewable energy sources have not been widely established, except in a few countries. Renewable energy use in Africa and the Middle East is projected to rise from 1.2 quadrillion Btu in 1999 to 2.6 quadrillion Btu in 2020. There have been several advances in the development of non-hydroelectric renewable energy projects in Africa. Morocco continued its pursuit of installing wind power. The state-owned utility Office Nationale d'Electricite (ONE) is planning to construct 200 megawatts of wind power at Tangiers and Tarfaya. The country's first wind power plant, the 50-megawatt Koudia al-Baida, began operating in May 2000 and is generating an estimated 200 million kilowatthours of electricity annually. Egypt also has made some advances in wind power, installing 30 megawatts of wind capacity on the Red Sea coastline south of Cairo in 2000, with plans to add another 60-megawatt build-own-operate-transfer (BOOT) wind project at Zafrana. The Egyptian New and Renewable Energy Authority (affiliated with the state-owned Egyptian Electricity Holding Company) hopes that wind will supply some 600 megawatts of electricity capacity to the national grid by 2007.[5]

[5] U.S. Energy Information Administration, *International Energy Outlook 2002*

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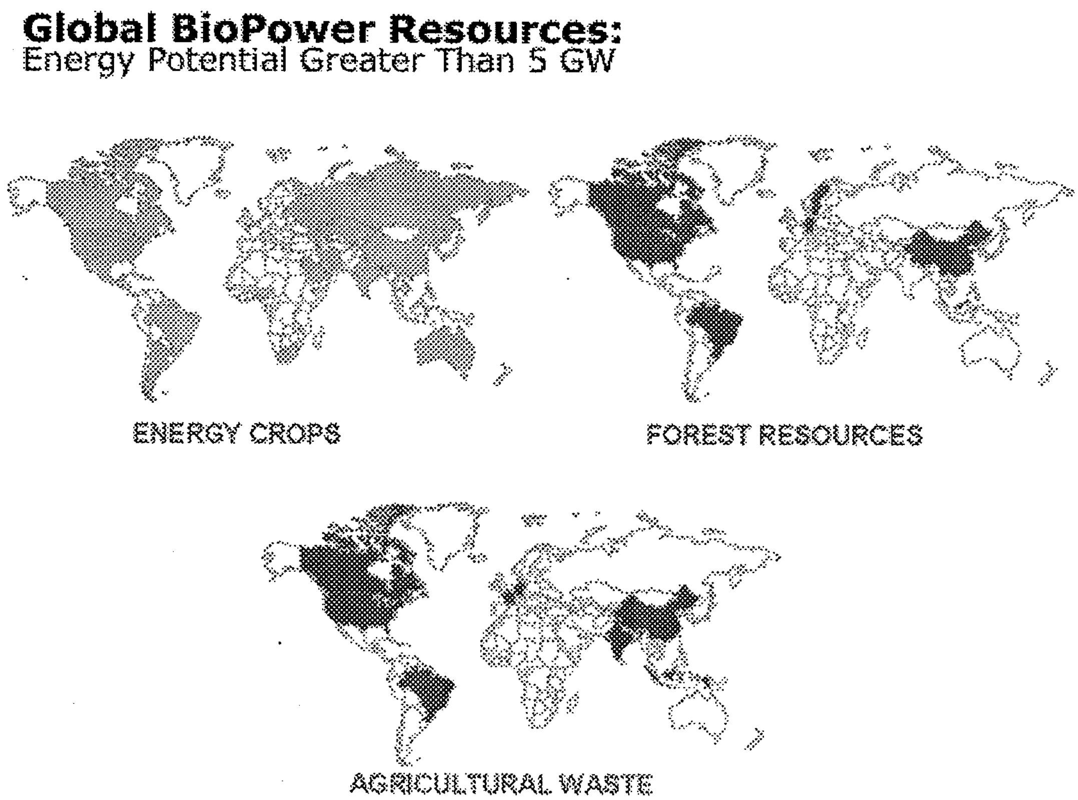
Technology Projections

BioPower

With an estimated 14,000 MW of annual worldwide installed generation capacity, BioPower is the largest source of non-hydro green power in the world. Worldwide BioPower generation is expected to grow to more than 30,000 MW by 2020. In many countries, local environmental conditions and global climate change concerns are further stimulating the demand for clean energy. Developing countries are the top markets because they meet several criteria: rapid economic growth, burgeoning demand for electricity, mounting environmental problems, need for rural electrification, need for reliable electricity, and significant agricultural/forestry residues.

According to the U.S. Energy Efficiency and Renewable Energy Network (EREN), studies indicate that additional (presently unused) quantities of economically available biomass may exceed 39 million tons per year in the U.S. -- enough to supply about 7,500 MW of new BioPower, or a doubling of the existing BioPower capacity. Economic availability of energy crops and crop residues could increase this quantity tenfold. The biggest near-term opportunity lies in co-firing, which offers power plant managers a relatively low cost and low risk route to add biomass capacity. These projects require small capital investments per unit of power generation capacity.

Figure 27: Global BioPower Resources



Source: EREN

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China and India are considered prime candidates for BioPower. The DOE estimates that by 2015, China will have between 3,500 and 4,100 MW of BioPower capacity and India will have between 1,400 and 1,700 MW. This is a sharp rise from their current levels of 154 MW and 79 MW, respectively. These two countries may also be good targets for co-firing operations because they have many older coal-fired power plants where biomass co-firing could be used to economically improve environmental performance. Other countries that show promising growth for a variety of BioPower systems are Brazil, Malaysia, Philippines, Indonesia, Australia, Canada, England, Germany, and France.

Geothermal

The word that best describes geothermal today is potential. International markets have shown huge potential. During the next 20 years, foreign countries are expected to spend $25 to $40 billion constructing geothermal power plants.

A report from the Geothermal Energy Association shows that geothermal resources using today's technology have the potential to support between 35,448 and 72,392 MW of electrical generation capacity. Using enhanced technology currently under development (permeability enhancement, drilling improvements), the geothermal resource could support between 65,576 and 138,131 MW of electrical generation capacity. Assuming a 90% availability factor, which is well within the range experienced by geothermal power plants, this electric capacity could produce as much as 1,089 Billion kWh of electricity annually.

The report also indicates that worldwide geothermal power could serve the electricity needs of 865 million people, or about 17% of the world's population. In light of significant worldwide exploration and development over the past decade, the results represent a refinement over previous estimates. However, these figures do not define the limits of the producible resource. Geothermal resources can be difficult to identify without more extensive investigation than has typically been conducted in most countries and new and improved technology is expected to continually expand the economically producible resource. Currently, approximately 8,000 MW are being generated in 21 countries from geothermal energy, and there are 11,300 thermal MW of installed capacity worldwide for direct-heat applications at inlet temperatures above 95°F.

In the U.S., 20 geothermal plants are in operation providing about 2,200 MW of capacity, while direct applications have an installed capacity in excess of 2,100 thermal MW. Geothermal power plants operate at high capacity factors (70 to 100 percent) and have typical availability factors greater than 95 percent. These plants produce clean power and require very little land. The savings in pollution emissions by displacing other, less desirable energy resources will be ever more important as the world strives to limit adverse environmental impacts, such as global warming.

Table 5: Geothermal Potential by World Regions

Region	Geothermal Potential (Billion kWh)	Current Electricity Use (Billion kWh)	% Geothermal
North America	200	4,333	4.6%
Central and South America	224	623	36.0%
Western Caribbean	354	669	52.9%
Europe/ Russia	97	4155	2.3%
Asia and Pacific	337	3304	10%
Africa	101	357	8.3%
World Total	1089	13,142	8.3%

Source: Geothermal Energy Association

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It has been estimated that identified hydrothermal resources in the U.S. could provide 23,000 MW for 30 years, and undiscovered resources might provide 5 times that amount. If it were to become economic to tap into more widespread "hot dry rock" resources (which involves deeper drilling and injection of water to recover the heat), the U.S. geothermal energy resource would be sufficient to provide our current electric demand for tens of thousands of years.

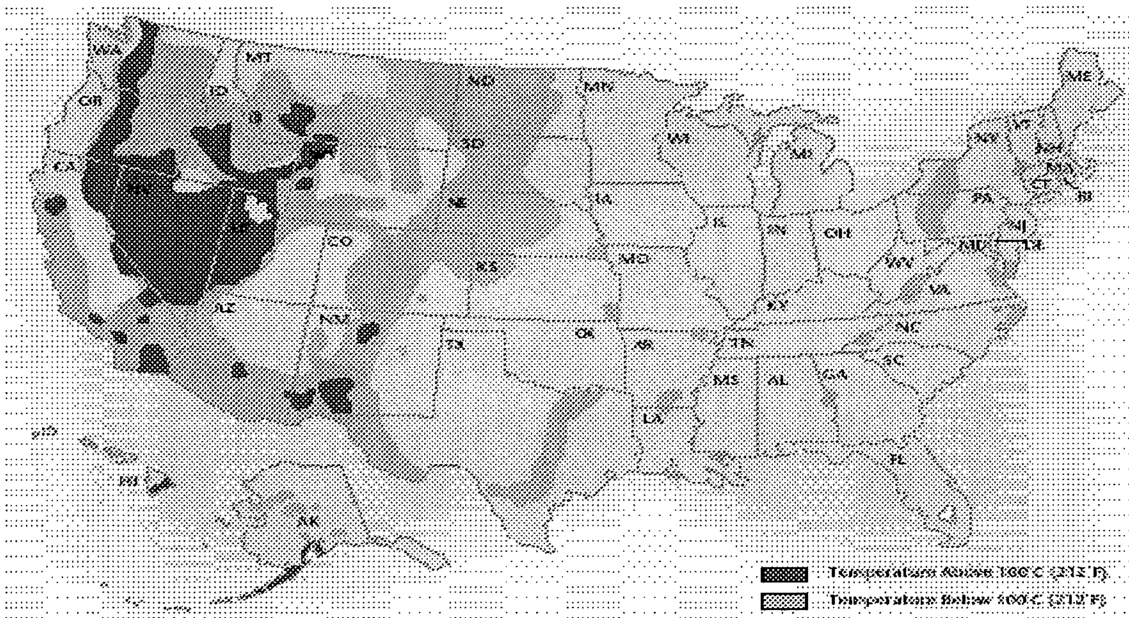
Most of the geothermal power in the U.S. is generated in California and Nevada with California accounting for over 90% of installed capacity. A considerable amount of this power (1,137 MW) is generated at The Geysers in Northern California, which has hosted a number of commercial geothermal power plants since the first one was built there in 1960. The Geysers is a fairly unusual (and ideal) resource because its wells produce virtually pure steam with no water.

Table 6: Major U.S. Geothermal Power Plants

Locality	Output (MW)	Years	Units	Plant Type
California:				
The Geysers	1,137	1960-89	23	Dry Steam
Coso	260	1987-89	9	Flash Steam
Salton Sea	267	1982-96	10	Flash Steam
East Mesa	105	1979-89	71	Binary-Cycle
Heber	80	1985-93	14	Flash and Binary-Cycle
Mammoth Lakes	43	1984-90	4	Binary-Cycle
Honey Lakes	30	1989	1	Hybrid: Geothermal/Wood
Amadee Hot Springs	2	1988	2	Binary-Cycle
Susanville (Wineagle)	1	1985	2	Binary
Hawaii:				
Puna	25	1992	10	Flash and Binary-Cycle
Nevada:				
Dixie Valley	66	1988	1	Flash Steam
Steamboat Springs	35	1986-92	13	Flash and Binary-Cycle
Soda Lake	17	1987-91	9	Binary-Cycle
Beowawe	16	1985	1	Flash Steam
Stillwater	13	1989	14	Binary-Cycle
Desert Peak	9	1985	2	Flash Steam
Empire	4	1987	4	Binary-Cycle, Crop Drying
Brady Hot Springs	21	1992	3	Flash Steam
Wabuska	1	1984-87	2	Binary-Cycle
SBH3	14	1988	1	Flash Steam
Utah:				
Cove Fort	11	1985-90	5	Dry Steam, Binary-Cycle
Roosevelt Hot Springs	20	1984	1	Flash Steam

Source: Geothermal Energy Association

Figure 28: US Geothermal Potential Map



Source: Geothermal Energy Association

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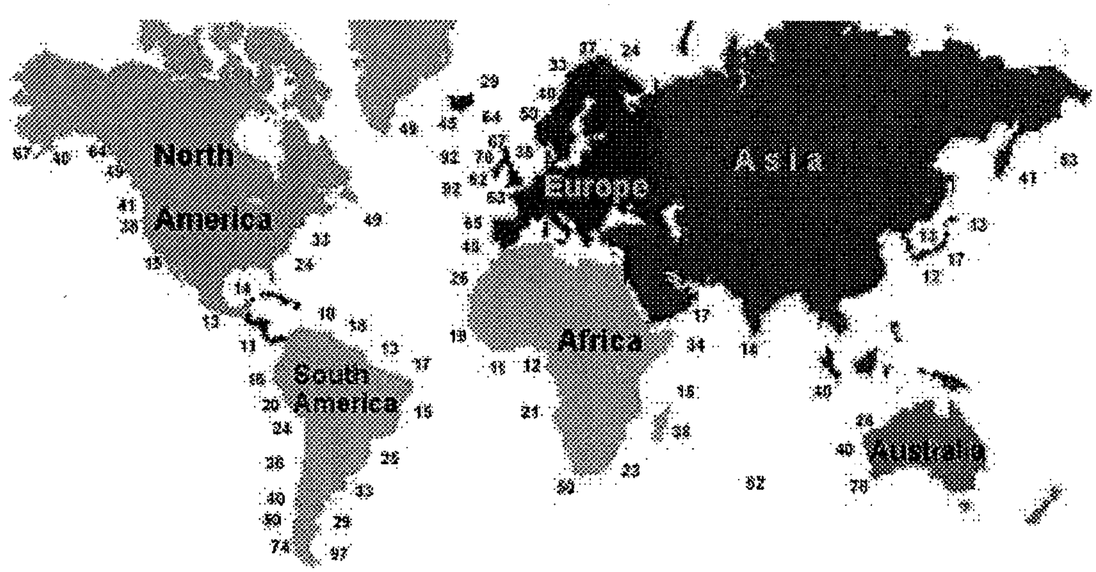
Ocean

As of 1995, 685 kilowatts of grid-connected wave generating capacity was operating worldwide. This capacity comes from eight demonstration plants ranging in size from 20 kW to 350 kW. Economic feasibility studies have been performed for a 30 MW wave converter to be located at Half Moon Bay, California. Additional smaller projects have been discussed at Fort Bragg, San Francisco and Avila Beach. There are currently no firm plans to deploy any of these projects.

OTEC is the most promising of the ocean technologies. Market opportunities have been identified for this technology as well as, albeit limited, wave technology. An economic analysis by EREN indicates that, over the next 5 to 10 years, OTEC plants may be competitive in four markets. The first market is the small island nations in the South Pacific and the island of Molokai in Hawaii. In these islands, the relatively high cost of diesel-generated electricity and desalinated water may make a small (1 MW), land-based, open-cycle OTEC plant coupled with a second-stage desalinated water production system cost effective. A second market can be found in American territories such as Guam and American Samoa, where land-based, open-cycle OTEC plants rated at 10 MW with a second-stage water production system would be cost effective. A third market is Hawaii, where a larger, land-based, closed-cycle OTEC plant could produce electricity with a second-stage desalinated water production system. OTEC should quickly become cost effective in this market, when the cost of diesel fuel doubles, for plants rated at 50 MW or larger. The fourth market is for floating, closed-cycle plants rated at 40 MW or larger that house a factory or transmit electricity to shore via a submarine power cable. These plants could be built in Puerto Rico, the Gulf of Mexico, and the Pacific, Atlantic, and Indian Oceans. Military and security uses of large floating plantships with major life-support systems (power, desalinated water, cooling, and aquatic food) should be included in this last category.

Figure 29: Relative Global Wave Energy Density (kW/meter)



Source: Wavegen Corporation

OTEC's greatest potential is to supply a significant fraction of the fuel the world needs by using large, grazing plantships to produce hydrogen, ammonia, and methanol. Of the three worldwide markets studied for small OTEC installations --U.S. Gulf Coast and Caribbean regions, Africa

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and Asia, and the Pacific Islands—the Pacific Islands are expected to be the initial market for open-cycle OTEC plants. This prediction is based on the cost of oil-fired power, the demand for desalinated water, and the social benefits of this clean energy technology. U.S. OTEC technology is focused on U.S. Coastal areas, including the Gulf of Mexico, Florida, and islands such as Hawaii, Puerto Rico, and the Virgin Islands.

A conservative estimate by the Commission of European Communities indicates a future (2005) wave energy market of 5.5 MW. Europe remains the world leader in wave energy technology. With some European countries investing in R&D or demonstration projects, the EU should be well placed to compete when a commercial market for the technology evolves. The following map illustrates the wave energy densities around the world.

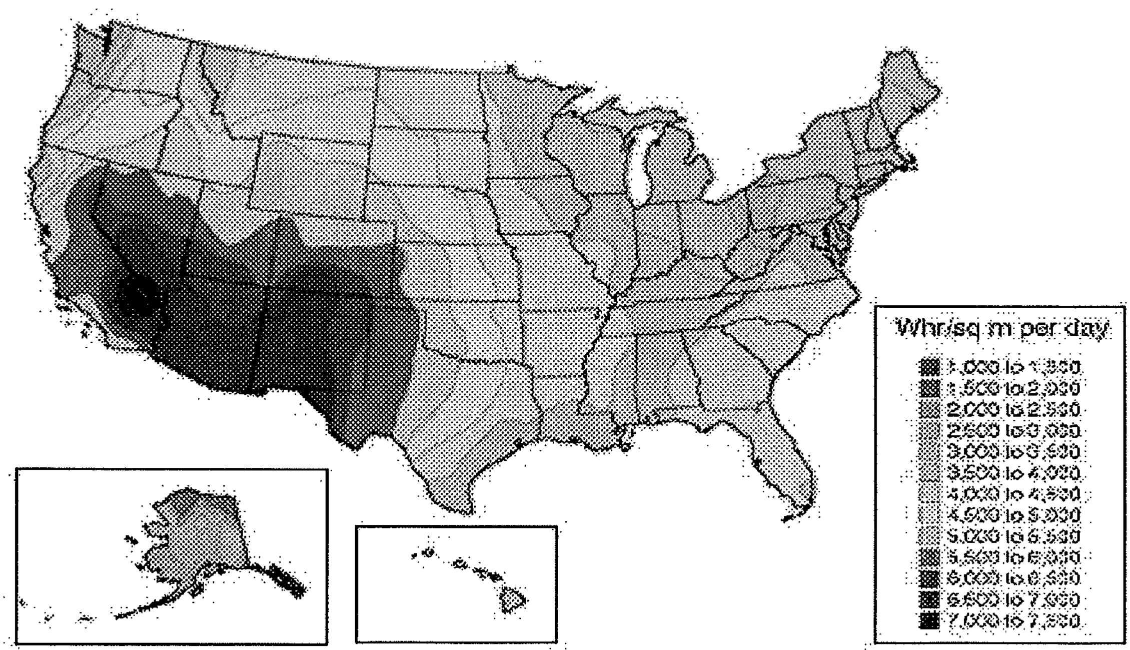
Solar

Solar technology has had the least penetration of the utility-scale market, but the most penetration of the distributed generation market. Analysts at EREN predict the opening of more specialized niche markets in the U.S. for the solar power industry over the next 5 to 10 years. The DOE estimates that by 2005 there will be as much as 500 MW of concentrating solar power capacity installed worldwide.

Perhaps the first of these niche markets to establish itself will be solar enterprise zones. Built to promote local economic development, these markets could enjoy special treatment by policymakers and lawmakers. Policies include tax equity such as accelerated depreciation of capital expenses, standard permitting, project financial structure, and allowing construction of multiple projects at a single location resulting in reduced operation and maintenance (O&M) costs.

One key competitive advantage of concentrating solar energy systems is their close resemblance to most of the power plants operated by the nation's power industry. Concentrating solar power technologies utilize many of the same technologies and equipment used by conventional central station power plants, simply substituting the concentrated power of the sun for the combustion of fossil fuels to provide the energy for conversion into electricity. This "evolutionary" aspect—as distinguished from "revolutionary" or "disruptive"—results in easy integration into today's central station–based electric utility grid. It also makes concentrating solar power technologies the most cost-effective solar option for the production of large-scale electricity generation. Although the quantity of solar radiation striking the Earth varies by region, season, time of day, climate, and air pollution, the yearly amount of energy striking almost any part of the Earth is vast.

Figure 30: U.S. Solar Concentration



Solar resource for a concentrating collector

Source: EREN

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The emerging grid-connected PV market provides a distributed generation resource to the electric grid. The PV system may tie to the grid at the substation to relieve transmission line load. A major portion of U.S. utilities, through recent cooperative research funded by the National Green power Laboratory, has identified the capacity contribution of PV to the grid. Capacity constraints in generation, transmission, and distribution are usually caused by solar-related loads such as air conditioning.

With restructuring of the domestic utility industry, these projects will be able to market their electricity directly to consumers by packaging the solar electricity as environmentally friendly. Many consumers participating in "green marketing" programs are willing to pay slightly higher prices and are choosing electricity suppliers who are environmentally friendly. Solar power can produce electricity in the price range that many environmentally conscious consumers are currently paying in these programs.

Table 7: Utility-Scale Solar Power Installations

PROJECT	DATE	HOST UTILITY	CAPACITY (kW)
Hesperia (Lugo)	1982	SCE	1,100
Kythnos Island	1982-1983	Greek PPC	100
Carrisa Plains	1983-1985	PG&E	6,100
Rancho Seco	1983-1985	SMUD	2,080
John F. Long Solar One	1985	Salt River Project	190
Austin PV-300	1986	City of Austin	300
Solar Hydrogen	1988-1989	Bayernwerk	140
PVUSA-US1	1989-1990	PG&E	210
Phalk 500	1990-1991	Bernische Kraftwerke AG	560
1,000 Roofs	1990-1992	all German utilities	1,500
Kerman	1992-1993	PG&E	650
SMUD Res. Rooftop Comm. Rooftop Grid Support	 1993 1993 1993	 SMUD SMUD SMUD	 440 40 250
HEDGE Substation	1994	SMUD	254
Ft. Davis	1994	CSWS	127
Monterey Hills Elem. School	1995	SCE	100
New Munich Trade Fair Center	Spring, 1997	Stadtwerke München	1,016

Most of the world does not enjoy the inexpensive power supplies that the U.S. does, so for many people, concentrating solar power offers a secure, indigenous energy supply. Solar is most competitive in areas where the infrastructure, such as natural gas pipelines, is either insufficient or not guaranteed.

Furthermore, many areas that are experiencing economic growth and will require substantial new power capacity in the next 10 years have excellent solar resources. These areas have good sites both for large-scale power projects consisting of troughs and power towers and for small-scale projects consisting of dish/engine systems for distributed or local grid support.

Finally, there is a huge, as yet untapped, market for supplying power to 40% of the world that does not yet have a reliable supply of electricity. Most of these people live in remote villages, many of which lie in the sun belt. Dish/engines will compete extremely well with diesel engines for these applications on the basis of performance, environmental impact, and cost. As solar power technology develops and costs become more competitive, its place in local and international markets will greatly expand.

Wind

Wind has been the fastest growing utility-scale energy technology in the world for the past decade. In 2001, the world wind industry installed a record amount of new utility-scale wind generation equipment, more than 6,000 MW, including a record installation of 1,700 MW in the U.S. Total wind power capacity in the world is now estimated at more than 24,000 MW. Much of the growth is due to cost reductions and government policies (specifically driven by the requirements imposed by Kyoto).

The pace of growth has been greatest in Europe. New figures from the European Wind Energy Association reveal another record year for wind power in Europe. During 2001 another 4,500 MW of wind power capacity was added to the European electric utility grids, bringing the total installed wind power capacity in Europe to more than 17,000 MW, an increase of more than 35%.

Growth in the European wind energy market has been so strong and steady that the European Wind Energy Association (EWEA) has raised its goal for the region by 50%, from 40,000 MW to 60,000 MW of installed capacity by 2010, of which 5,000 MW are expected to be offshore capacity.

According to the latest World Market Update from the Danish company BTM Consult, world wind power will almost triple by 2005 –and grow again by a factor of 2½ by 2010. Most of the growth in the nearest future is predicted for Europe, while the report takes a dim view of the American market. Offshore could be the next big wave, or not, depending on whether current projects in the works can prove viable. If wind capacity indeed reaches the levels forecast for it by the end of the decade, however, it will still be making little impact on world electricity supplies due to the growth of global electricity consumption.

With steady growth in Europe and a string of projects in other countries, the global outlook for wind is very bright. About 1,470MW of new capacity is forecast to be installed in Europe annually from 2002 to 2005, resulting in almost 17,000MW of total capacity by 2005.

Table 8: Global Wind Power

Year	Installed Capacity (MW)
1980	10
1985	1020
1990	1930
1995	4820
2000	13507

Source: Irish Renewable Energy Strategy Group

Wind energy is the fastest growing form of energy production, with an estimated year-on-year growth of 25%. According to the US Department of Energy's (DOE) National Renewable Energy Laboratory (NREL), the cost of wind energy has declined from $0.40 per kWh in the 1980s to less than $0.05 per kWh today. By 2006 wind power exploitation costs are expected to decline by a further 35%-40%.

Table 9: European Wind Power (Dec. 2001)

Country	Total Installed MW
Germany	8754
Denmark	2417
Spain	3337
Netherlands	493
UK	474
Italy	697
Sweden	290
Greece	272
Ireland	125
Portugal	125
Austria	94
Finland	39
France	78
Norway	17
Czech Republic	12
Luxembourg	15
Belgium	31
Poland	22
Switzerland	7
Romania	1
Turkey	19
Total	**17,319**

Source: European Wind Energy Association

The Mediterranean region is beginning to tap its winds. Just south of one of Europe's most dynamic wind energy markets, Spain, has an installed capacity in excess of 1,000 MW. Italy increased its total installed capacity by more than 60%, adding 270 MW during 2001 to reach a total of 700 MW. Further to the east, Egypt saw 30 MW of new wind energy go online on the Red Sea coastline about 250 km south of Cairo. Turkey has approved contracts for projects totaling several hundred MW of new wind energy.

By contrast, the Asian and Latin American markets -- with the exception of Argentina -- remain uncertain. India and China, with historically the largest amount of installed wind energy generating capacity among developing nations, have only developed a small amount of their wind energy potential. In Central America, green power still faces barriers even as electricity markets are restructured. Nicaragua's newly privatized power utility, ENEL, retracted its bid for a 22 MW wind project in response to the Inter-American Development Bank's energy restructuring policy requirements (the bid had been won by a consortium involving Iberdrola/ENISA and Dallas-based International Wind Corp.). Even though wind energy is very price-competitive in the region, this example shows that wind projects will not be implemented in the region if restructuring and privatization proceed without including effective provisions to promote green power.

Canada's wind energy generating capacity is at 205 MW, according to the Canadian Wind Energy Association (CanWEA). The province of Quebec has the most installed wind capacity, followed by Alberta. However this may soon change if the recommendations made by Ontario's Select Committee of the Legislature on Alternative Fuel Sources are adopted by the government. CanWEA believes it would lead to a large and vibrant wind energy industry in the province. The Committee recommendations included many that would remove barriers to the development of the wind industry. CanWEA estimates that there are well over 3,000 MW of commercially viable wind energy in the province which, if developed, would result in thousands of jobs in construction, manufacturing, wind resource assessment and maintenance. The development of 3,000 MW of wind energy would result in $4.5 billion in investment for the province, and would supply 5% of the province's power. Ontario currently has only 3 MW of wind capacity installed.

Following an all-time high of 1,696 MW of new U.S. installations in 2001, the current year was expected to be a "breather" year, especially when the extension of the wind Production Tax Credit was delayed until March. AWEA is projecting 400 to 450 MW of new wind capacity will be installed in the U.S. in 2002, a slight decrease from the approximately 600 MW projected in April. A number of projects have been delayed until 2003 for a variety of reasons, but those delays do not reflect any fundamental change in the market.

Wind energy has only recently gained a foothold in the midwestern U.S., which has far greater wind potential than in California. In Minnesota, a 1994 legislative mandate required Xcel Energy Company (formerly Northern States Power) to purchase 425 MW of wind generated electricity by 2002 in return for granting dry cask storage of its spent nuclear fuel. Because wind was demonstrated to be the least cost resource, Xcel is required to purchase an additional 400 MW of wind generation by 2012. The Texas state legislature has required that 2,880 MW of generating capacity from renewable sources (equivalent to about 3% of the state's electricity production) be built by 2009, with most expected to come from the state's abundant wind power. Large wind farms now online in farming and ranching states including Texas, Minnesota, Iowa, and Wyoming. The World Energy Council has estimated that wind energy capacity worldwide may total as much as 474,000 MW by the year 2020, and the federal Wind Powering America initiative aims to have more than 10,000 MW of wind capacity in the U.S. by 2010.

The wind in the U.S. could produce more than 4.4 trillion kWh of electricity each year--more than one and one-half times the 2.7 trillion kWh of electricity consumed in the U.S. in 1990. The following map shows annual average wind resources using the 7 wind power classes, which are ranges used to describe the energy contained in the wind.

According to the American Wind Energy Association (AWEA) some $3 billion worth of wind power investments (about 3,000 megawatts, or enough to supply the needs of 850,000 homes) are being proposed or planned for the next several years in the U.S. There are now wind turbine installations in 26 states providing 4,261 MW of clean, renewable wind energy to consumers nationwide.

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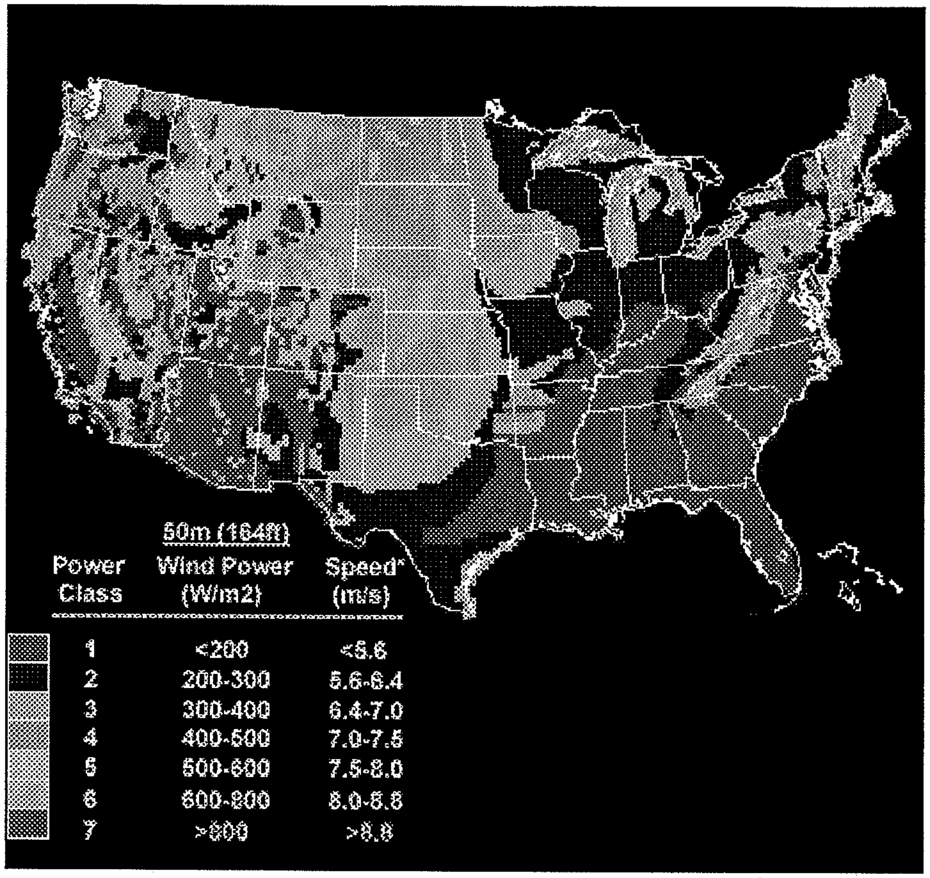
Figure 31: U.S. Wind Potential Map



Source: NREL

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Table 10: Country-By-Country Wind Power Installations

Country	Wind Energy (MW)					Rate of Growth	Installed Capacity per Capita [Watt/ capita]	Area [km²]	Installed Capacity per Area [kW/km²]	GNP 1997 [$ billion]	Installed Capacity per GNP [MW/$ bn]
	End of '99-2000	End of 1999	End of 1998	End of 1997	2000						
Germany	5,432	4,443	2,875	2,081	989	22.26	66.19	357,021	15.2148	2,320.98	2.34
USA	2,495	2,473	1,820	1,673	22	0.90	9.32	9,809,155	0.2544	7,783.09	0.32
Spain	2,099	1,542	834	427	557	36.12	53.38	504,782	4.1582	569.64	3.68
Denmark	2,016	1,771	1,383	1,066	245	13.83	381.82	43,094	46.7815	184.35	10.94
India	1,094	1,062	968	940	32	3.06	1.14	3,287,365	0.3329	357.39	3.06
Netherlands	434	411	361	319	23	5.60	27.80	41,526	10.4513	403.06	1.08
UK	391	353	333	319	38	10.76	6.63	243,307	1.6070	1,231.27	0.32
Italy	350	283	180	103	67	23.67	6.08	301,323	1.1615	1,160.44	0.30
China	302	261	214	166	41	15.71	0.25	9,572,395	0.0315	1,055.37	0.29
Sweden	228	215	174	122	13	6.05	25.76	449,964	0.5067	231.90	0.98
Greece	186	82	39	29	104	126.83	17.68	131,957	1.4096	122.43	1.52
Canada	126	125	82	25	1	0.80	4.16	9,958,319	0.0127	594.98	0.21
Ireland	93	73	73	53	20	27.40	25.41	70,273	1.3234	65.14	1.43
Japan	81	68	40	18	13	19.12	0.64	377,819	0.2144	4,812.10	0.02
Portugal	74	60	60	38	14	23.33	7.44	92,345	0.8013	109.47	0.68
Austria	55	42	30	20	13	30.95	6.82	83,858	0.6559	225.37	0.24
Morocco	54	0	0	0	54	-	1.98	458,730	0.1177	34.38	1.57
Egypt	53	35	5	5	18	51.43	0.88	1,002,000	0.0529	72.16	0.73
Costa Rica	51	46	26	20	5	10.87	14.74	51,060	0.9988	9.27	5.50
France	41	22	19	10	19	86.36	0.70	543,965	0.0754	1,541.63	0.03
Finland	38	38	17	12	0	0.00	7.39	338,144	0.1124	127.34	0.30
New Zealand	35	35	5	4	0	0.00	9.31	270,534	0.1294	59.54	0.59
Brazil	20	20	17	3	0	0.00	0.12	8,547,404	0.0023	784.04	0.03
Turkey	19	9	9	0	10	111.11	0.30	779,452	0.0244	199.31	0.10
Luxembourg	15	10	9	2	5	50.00	35.71	2,586	5.8005	18.85	0.80
Argentina	13	13	12	9	0	0.00	0.36	2,780,400	0.0047	319.29	0.04
Norway	13	13	9	4	0	0.00	2.95	323,758	0.0402	158.97	0.08
Australia	11	10	9	4	1	10.00	0.59	7,682,300	0.0014	382.70	0.03
Iran	11	11	11	11	0	0.00	0.18	1,648,000	0.0067	108.61	0.10
Belgium	9	9	6	4	0	0.00	0.88	30,528	0.2948	272.38	0.03
South Korea	8	7	2	2	1	14.29	0.17	99,313	0.0806	485.21	0.02
Israel	8	8	6	6	0	0.00	1.37	22,145	0.3613	94.40	0.08
Poland	7	7	5	2	0	0.00	0.18	312,685	0.0224	138.91	0.05
Mexico	5	3	3	2	2	66.67	0.05	1,953,162	0.0026	348.63	0.01
Russia	5	5	5	5	0	0.00	0.03	17,075,400	0.0003	394.86	0.01
Totals	15,887	13,580	9,653	7,516	2,308	16.99	N/A	N/A	N/A	N/A	N/A

Barriers to Implementing Green Power

While utility-scale green power is starting to take off, there are still a number of barrier hampering the spread of distributed green power.

There are government policies which prevent utilities from deferring distribution upgrades with distributed green power. Using customer-sited green power to save on transmission and distribution (T&D) costs means crediting savings in the T&D monopoly against the cost of a competitive activity. Applying monopoly T&D benefits to competitive customer-site generation would be an anti-competitive ratepayer cross-subsidy, helping the utility to leverage its monopoly franchise into an area where there is no natural monopoly. This applies regardless of whether the green power is connected on the customer side of the meter, as with single net metering, or on the utility side of the meter. Consequently, acting as both catalyst and constraint, regulation becomes extremely important to remember when discussing the barriers to implementation.

Interconnection Requirements
Currently, utilities and governments have varying requirements for interconnecting non-utility owned green power generation with the distribution grid. Generally, customers that interconnect such distributed resources with the system grid must meet technical interconnection and liability requirements. These requirements have been designed to ensure that distributed systems operate safely and reliably with the distribution system, but they have evolved to be so complex and burdensome that they may hinder the deployment of distributed technologies.

To allow for the development of a robust national market for green power in the increasingly competitive electricity industry, there is a need for uniform technical interconnection standards nationally and simplified contractual and other interconnection requirements at the state and local levels. Simplified interconnection requirements would help minimize engineering and design costs, streamline the installation and operation of distributed green power systems, and increase safety by promoting the use of simpler, more reliable protective relaying systems.

The need for standardized interconnection on a national basis is a major barrier to green power. While some onsite green power may be interconnected to the grid and may be able to take advantage of streamlined procedures to sell power during periods of high demand, this is not universal. The DOE has released a study outlining barriers to interconnection, entitled *Making Connections: Case Studies of Interconnection Barriers and Their Impact on Distributed Power Projects.* This study offered details of 65 case studies of interconnection, ranging in size from a few kilowatts, to large cogeneration facilities. Only seven projects "reported no major utility-related barriers and were completed and interconnected on a satisfactory timeline."

Business practice barriers arose in the form of contractual requirements. Often times, customers had difficulty finding utility personnel with the competency and authority to act. Particularly important for smaller customers, utilities erected barriers toward implementation of grid-intertie, partly due to a lack of uniform standards. Utilities with procedures and a point of contact were able to avoid costs for themselves and the green power operator. Additionally, utility approval, application fees (arbitrary amounts), insurance requirements and operational protocol created a lengthy time constraint for the operator.

In March 1999, the Institute of Electrical and Electronics Engineers (IEEE) Standards Association Board voted to undertake the development of uniform standards for interconnecting distributed resources with electric power systems. The IEEE Standards Coordinating Committee, the committee responsible for developing technical standards for distributed technologies, is now working to develop IEEE P1547, the Standard for Distributed Resources Interconnected with Electric Power Systems. The consensus standard will contain specific requirements related to performance, operation, testing, safety, and maintenance of interconnections between distributed resources and other electric power systems.

In January 2000, the IEEE Standards Board approved a standard for interconnecting PV systems under 10 kW to the utility grid. The standard is entitled Recommended Practice for Utility Interface of Photovoltaic Systems. This recommended practice contains guidance regarding equipment and functions necessary to ensure compatible operation of PV systems that are connected in parallel with the electric utility. This includes factors relating to personnel safety, equipment protection, power quality, and utility system operation. This recommended practice also contains information regarding islanding of PV systems when the utility is not connected to control voltage and frequency.

Some states are taking control and developing their own standards for interconnection. For example, in July 1999, the Arizona Corporation Commission initiated a "General investigation of Distributed Generation and Interconnections (DGI) for potential retail electric competition rules consideration." The final report included the identification of key stakeholder issues and recommendations for developing standards, policies and tariffs for distributed generation. These included the following recommendations:

- Design fair and reasonable tariffs considering the benefits and costs of DG to the utility distribution grid.
- Address operational issues, such as the scheduling and accounting of DG energy transactions.
- Address certain technical issues and processes necessary to interconnect DG to the grid.
- Define planning processes needed for DG operating in parallel with the distribution grid, and consider appropriateness of public access to distribution system operational information.
- Address DG applications on network distribution systems.
- Establish a periodic review process for monitoring the progress of implementing the policies and standards necessary for distributed generation.

Another state that has been working to adopt a set of interconnection standards for green power has been California. In December 1998, the California Public Utilities Commission (CPUC) issued an order instituting a new distributed generation rulemaking that would be implemented in two phases. The first phase addressed interconnection standards. A standard interconnection procedure was agreed on. First of all the green power facility or the distributed generation site must supply sufficient information to allow the utility to accurately evaluate the interconnection requirements for the facility but not be so burdensome that it becomes a barrier to entry. The application has been designed to ensure that the applicant for interconnection understands what information is required for the application to be processed without the utility having to request additional information. Secondly an agreement has to be signed. The agreement proposed by the CPUC states that each party is held harmless from any damages, losses, and liabilities resulting from the other party's performance under the contract, except in the case of gross negligence or intentional misconduct.

Electric Rate Design

There is a lack of well-articulated, coherent green power policy at the federal, state and local levels. This includes an absence of regulatory incentives to encourage green power from the utility's standpoint to minimize T&D costs. Removing public utility commission regulations impeding green power investment can provide support. From a customer standpoint, as distributed generation becomes less expensive and more cost effective, customers may move to standby service. The crafting of standby tariffs to collect fixed costs normally collected through rates is receiving much attention. Utilities will likely attempt to collect a larger portion of their fixed costs in customer charges, rather than in rates. In this way, they will be able to collect fixed costs, including transition charges, in ways not affected by deferral of electric consumption from the grid. Regardless of their merits, fixed charges will discourage green power. Utilities are starting to propose increased fixed monthly customer charges and decreased usage charges for distribution services. This will certainly make green power far less attractive to customers, and may propel customers who choose green power to become grid isolated.

A significant regulatory barrier regarding tariff structures is the prohibition of "parallel operation" -- any use other than emergency backup power when disconnected from the grid. Backup and standby charges are a significant rate-related barrier. Charges for these services range from $50-200kW per year in New York. Moreover, these charges do not reflect benefits if the green power unit provides power back to the grid.

In California, the CPUC discussed rate design in Docket #99-10-065.

> Some possible rate design options included: standby charges that reflect different levels of reliability, for example, firm standby or non-firm service; or standby charges that reflect the frequency of use, such as a low reservation charge and a high usage charge; or a fixed connection charge, as opposed to the current charge based on capacity and energy; or standby charges based on a TOU rate structure; or a standby charge that differentiates between planned outages and unscheduled outages; or allowing the utilities to establish contracts with customers that would require the customer to give an extended notice before the customer could depart the distribution system.
>
> If more customers elect to disconnect from utility service entirely, the remaining customers will bear a greater burden of the costs of operating the T&D system unless some sort of bypass charge is imposed on the departing customers, or some other allocation of costs is developed. PG&E has requested authorization to charge bypass fees in Phase 2 of its general rate case, Application (A.) 99-03-014. The bypass charge is also referred to as an exit fee. The rationale for imposing the charge is that it allows the utility to recover some or all of the perceived stranded costs of the facilities that were used to serve the departing customer.

Competitive Transition Charges

Compensating utilities for stranded costs in facilities, such as nuclear plants and other investments, appears necessary. If customers are required to pay a CTC, it will have a negative impact on the value customers place on green power. Quite possibly, CTCs can negate the entire customer savings. A recommendation has surfaced in California regarding users installing green power. Users could receive a reprieve (longer payback period), or discount on the CTC, or be given an incentive if it can show green power would be in the public's interest.

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Other recommendations in California suggest green power should not receive special treatment, but receive recognition commensurate with its benefits. Performance Based Ratemaking (PBR) becomes an issue. For example, in addition to providing power and other premium power commodities, green power could be an excellent source of ancillary services (peak power, spinning reserves, voltage support, power factor support, etc.) used by Independent System Operators (ISO).

The National Association of Regulatory Utility Commissioners (NARUC) believes states should retain jurisdiction to address the recovery of costs for power sales and delivery service provided retail customers regardless of the facilities used. This means that technical definitions as to the designation of facilities as T&D investments should not infringe upon the ability of state commissions to exercise authority over retail transactions. This issue is of critical importance to ensure that states have the option of imposing non-bypassable charges to fund stranded cost payment. In the absence of this assurance some customers could bypass the local distribution system thus leaving a smaller customer base responsible for stranded cost payment.

Net Metering

Net metering is a concept whereby green power system owners can sell excess power they generate back to the grid. The way it works in general is that when a customer takes electricity from the grid, a single, bi-directional meter runs "forward." When the customer uses a green power system and generates more electricity than they use, it goes back to the grid and the meter runs "backward," hence the name "net metering." This is somewhat different from net purchase and sale metering, which uses two meters, and the green power owner is typically paid "utility avoided cost" for the sale while paying retail market rates for the purchase.

Most net metering rules call for month-to-month carry forward of any "net excess generation" until the end of a year. If, over the period of a month, a customer generates more kWh than they use, the net excess generation is carried over to the following month. In the event that there is excess generation left at the end of the year, it is either "paid-off" to the customer, or in most cases, granted to the utility with no payment. The provision for annualized netting reflects the fact that some green power resources are seasonal in nature.

Net metering provides a variety of benefits for both utilities and green power owners. Utilities benefit by avoiding the administrative and accounting costs of metering and purchasing small amounts of excess electricity produced by green power facilities. Owners benefit by reducing the overall cost of green power. The actual monetary benefit to owners is dependent on whether or not they are paid for net excess generation, as well as the difference between retail rates and avoided cost rates.

Utility Status

Green power units connected to the grid may be considered utilities based on different state legislation. When this happens, regulators on both the state and federal level will face the challenge of overlapping jurisdiction. While transmission rates for power sold for purposes of resale fall under the FERC's jurisdiction, the industry must recognize that most onsite green power units are connected directly to utility distribution systems, not the transmission grid. It may be easier to make sales within local territories -- to the local utility or to a neighboring facility -- than to a marketer operating at the ISO level. Utility status will be of concern to the owners of onsite green power units, and could serve as a barrier to entering the market. Delaware addressed this concern in its restructuring legislation by allowing onsite green power to sell electricity to up to five contiguous neighbors without triggering utility status. It is anticipated that the Public Utility Holding Company Act (PUHCA) will be repealed at the point

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that federal electric restructuring becomes a reality. Until that happens, it may be necessary to fashion some form of streamlined exemption for the owners of onsite green power. To the extent FERC could facilitate such a process remains a question.

Siting and Permitting Processes
Another area of regulatory challenge is the permit certification process. The "need determination" test is traditionally performed in Integrated Resource Planning (IRP) and reaffirmed in the site certification process. Assuming IRP is under local or state jurisdiction in the future, the transaction costs associated with any "need" hearings would reduce the capital cost savings provided by green power.

The other area of concern is how small, advanced turbines and microturbines, are exempt from review under current air quality regulations. In the aggregate, these units would equal a larger unit normally subject to jurisdictional review. Aggregating these units over a three-to-five year horizon, to establish jurisdictional review, is one way to overcome this concern. Quantifying the environmental benefits of lower emissions is viewed as both a benefit (typically lower emissions than centralized plants) and a barrier (calculating emissions is a lengthy and costly process). Analytic tools/software must be developed in order for utilities to appropriately price the energy stream. Customers can attempt to quantify the environmental and economic benefits accelerating the siting/permitting process. However, the inconsistency of uniform environmental policy between states, and site-to-site, is seen as a barrier.

Potential Barriers to Implementation for Utilities:

- Electric rate structure -- including lack of incentives to use green power to minimize T&D cost upgrades.
- Supplemental rate structure -- including peak-shaving and inter-operable systems -- based on actual costs, not theoretical costs differentiated by technology.
- Compensation for stranded costs and CTC implementation.
- Performance Based Ratemaking -- price or revenue based.
- Utility status -- licensing of DG owners/operators isolated from the grid.

Potential Barriers to Implementation for Customers:

- Large initial investment.
- Lack of standardized interconnection requirements.
- Arbitrary interconnection processes imposed by utilities.
- Certification requirements of equipment.
- Net Metering -- lack of "fair" price on power delivered to the grid.
- Siting and Permitting -- need hearings and calculating aggregate emissions are costly.

Suggestions for Reducing Barriers:

- Adopt uniform technical standards for interconnecting green power to the grid.
- Adopt testing and certification procedures for interconnection equipment.
- Accelerate development of green power control technology and systems.

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- Adopt standard commercial practices for any required utility review of interconnection.
- Establish standard business terms for interconnection agreements.
- Develop tools for utilities to assess the value and impact of green power at any point on the grid.
- Develop new regulatory principles compatible with green power choices in both competitive and utility markets.
- Adopt regulatory tariffs and utility incentives to fit the new green power model.
- Establish expedited dispute resolution processes for green power project proposals.
- Define the conditions necessary for a right to interconnect.